BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Maria Pope
Brett Sims

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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.
- Describe the customer value and benefits from investments we have made to enable a clean energy future with a stronger, smarter, more resilient, better integrated electric grid.
- Discuss actions to keep electricity prices as low as possible as we make these investments, serving customers efficiently and equitably.
- Summarize the proposed average all-in price increase in 2022 of 3.9%, 2.9% of which is supported by this filing,[1] (the proposed price changes for specific classes of customers is detailed in Exhibit 1200, Pricing).
- Identify key proposals and provide Commissioners, Staff, and stakeholders a roadmap for our filing.

Our testimony is organized according to these objectives.

[1] The all-in price increase is comprised of the following: 2% for NVPC; 2.9% base rate increase; less 0.9% for supplemental schedules and less 0.1% for cycle basis billing.

Q. Please provide a brief description of PGE.

A. As a vertically integrated, regulated electric utility company, PGE proudly serves more than 900,000 customers in 51 Oregon cities, including the state's rapidly growing population centers in the City of Portland, tri-county metropolitan area and north Willamette Valley. Our service territory encompasses 4,000 square miles, reaching roughly from Mt. Hood west to Gaston and Grand Ronde and from the Portland metropolitan area south to Salem. Headquartered in Portland since 1889, we have more than 2,900 employees in counties across Oregon – making us one of the state's largest employers. We are a key economic engine with the responsibility and privilege of providing essential electric service for our fellow Oregonians. This requires safe, reliable, and affordable power, while also making investments like our Wheatridge Renewable Energy Facility, which combines wind, solar and batteries and projects such as our smart grid test bed to build a cleaner, smarter, and more equitable energy future benefiting all customers and communities. We pride ourselves on reflecting the values of the customers and communities we serve and taking action to support their needs. We are also inspired by the opportunity to partner with them to go further, faster to address climate change. Several cities and counties in our service area have adopted resolutions to move to 100% carbon-free power, and our voluntary renewable energy program leads the country in both customer participation and the amount of energy sold.

Q. Please state PGE's mission and strategic vision.

A. Our fundamental mission remains unchanged: Deliver safe, reliable, secure, and affordable energy to Oregonians as a regulated and integrated utility. Reliability and affordability are the foundation of our role in supporting customers, Oregon's economy, and the overall advancement of society. Yet the drivers that guide how we fulfill our mission – and expectations for how quickly we must act on those drivers – have evolved as the impacts of climate change and other environmental concerns mount and societal awareness of systemic inequalities expands. In that context, our strategic vision is to integrate the delivery of affordable, cost-effective customer choices with our approach to decarbonization and our role of ensuring reliability, resiliency, and access for all through a smarter grid. One core aspect of our strategy is to decarbonize our energy supply for the energy we serve customers by 80% or more by 2030 and achieve net-zero carbon across the enterprise by 2040 when we aim to reach the goal of delivering 100% carbon free energy to customers. We will also work with customers and others to further decarbonize our economy by electrifying it through the increased use of grid-connected electric vehicles, water heaters, heat pumps, and other clean technologies, and to achieve these goals on our customers' behalf as efficiently and equitably as possible. The investments and initiatives reflected in this rate case are part of that effort.

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

A. Yes. While the past one and a half years have been challenging, recent events have solidified the importance of our mission more than ever. In addition to the Covid-19 pandemic, Oregonians have endured historic wildfires, unprecedented winter storms, and record-breaking summer heat that may represent "new normal" events as our climate changes. During this time our society also awakened to a compelling new sense of urgency around the need to address systemic inequality and racial bias so that all members of the community are treated equitably.

These challenges have illustrated again how essential the service we provide truly is for our customers, and how critical it is for us to transform and modernize the electric system by investing in smart and clean technologies that help us address climate-driven and human-caused threats to service reliability. At the same time, we must use this opportunity to rapidly increase efficiency and reduce costs by leveraging technology to transform and improve our business so we can keep customer prices affordable. We are being purposeful in partnering with our customers, communities, and other stakeholders to seek innovative and equitably delivered solutions as we formulate and execute our strategy.

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

A. In our last general rate case, we discussed in-migration to our service territory, the growing customer connects and the need to meet increasing demand. Since then, exacerbated by the pandemic, we have seen small businesses reduce operations or go out of business and more customers – residential and business – experience difficulty paying their bills. We responded with a voluntary moratorium on disconnecting customers for nonpayment, which was extended to August 2021[2] for residential customers and was effective until December 1, 2020 for nonresidential customers. Our voluntary efforts are memorialized in a stipulation we entered with stakeholders, facilitated by Commission Staff and approved by Commission Order No. 20-324. There are strong indications that economic recovery in Oregon and across the nation is accompanying widespread vaccination against COVID in 2021 and will continue through 2022, yet we understand that for some customers the impact of the pandemic will be felt for an extended period. We took that into account in determining the scale and timing of this rate case and have worked to minimize the impact on customers while still providing for essential investments needed to assure reliable service and enable grid transformation. Details of those efforts are provided below. In addition, we continue to work with customers who are struggling to pay their bills, and with Commission Staff and stakeholders, to look for

[2] For residential customers, energy utilities may resume the 15-day disconnection notice (in accordance with OAR 860-021-0405) on August 1, 2021.

appropriate avenues to ease the burden on these customers, including our support for legislation adopted this year to give the Commission authority to consider differential pricing for energy burdened customers.[3]

Q. Given the pandemic and resultant customer hardships, did you consider not filing this general rate case?

A. Yes. In making the decision to file this general rate case, we actively considered the pandemic and its effects on our customers, many of whom lost jobs, businesses, or had other cutbacks in employment, and are challenged making ends meet. We have seen this first-hand through sometimes distressed calls from customers who cannot pay their bills. Given this, we analyzed the consequences for customers and our ability to deliver on customer-driven priorities if we were to delay filing a rate case. We concluded that, while a rate case filing in 2021 is a practical necessity, we could – and did – minimize the price increase request, and we filed later in the year to allow recovery from the pandemic to begin and the economy to start to rebound. The decreased proposal reduces the immediate impact on customers, while the delay in filing until mid-year moves the effective date for a Commission-approved price change in 2022 further into what is anticipated will be the post-pandemic economic recovery (and out of the high bill season during the winter months).

Q. Is there any significance to the timing of this rate case filing?

A. Yes. As noted above, we decided to submit the filing at a later date so the smaller price increase will become effective in May 2022, when residential customer loads are traditionally lower due to milder temperatures, rather than January 1, 2022 when, with colder weather and

[3] See HB 2475; https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2475/Enrolled

less daylight, loads are higher. Consequently, the proposed increase will take effect later and have less overall impact for most customers than would otherwise have been the case.

Q. How is the rest of your testimony organized?

A. In the next section, we explain how PGE's strategic vision relates to current State of Oregon and Commission policy. We also explain how this general rate case fits into this larger context. Next, we summarize the average price increase proposed in this case and the primary drivers of that increase, as well as our efforts to mitigate cost impacts 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 role do customers play in driving your strategy?

A. Our strategic vision to decarbonize, electrify and perform can only be successful if it is informed by and reflects customer values and desires.

We understand that our customers care deeply about the environment and the planet, and that they expect PGE to be a leader in addressing climate change and we are working to meet our shared priorities to accelerate sustainability and decarbonization. We also know customers want us to provide more offerings and better solutions for their individual energy needs, as well as customized options involving the deployment of new technologies and innovative programs and services. Finally, we know our communities recognize the urgent need to address systemic inequalities and achieve more equitable outcomes across all institutions and segments of our society and economy. And they expect these priorities to be achieved while maintaining the foundational mission of safe, reliable, and affordable electric service.

To accomplish this, we need to meet our customers' evolving needs and expectations. Our first priority has been to invest in our transmission and distribution (T&D) system to maintain and build its strength as equipment has aged out and as we face new challenges with extreme weather and wildfires. Our customers do not just expect us to provide them with clean energy seamlessly and affordably; they also expect us to be easy to do business. Our customers expect us to make thoughtful investments, operate prudently, meet all regulatory standards and requirements, and think ahead to anticipate their future needs, while also being transparent and inclusive. We aspire to be our customers' trusted energy advisor, engaging with customers in creative and continuous ways to ensure that we understand what they want from us so customer priorities can drive our actions.

Q. Please provide specific examples of customer-driven strategy and priority.

A. Our focus on decarbonizing our energy supply and partnering with customers and communities to electrify and reduce transportation sector emissions is informed by the majority of our customers who want cleaner energy sources to serve their needs and address climate change. In this vein, we now offer residential and nonresidential charging rebates, EV chargers on distribution poles for our customers who may not have home charging, nonresidential heavy duty EV charging, and assistance in conversions of fleet to electric vehicles.

Our customers also want new and individualized ways to engage with service providers of all kinds – whether through traditional means like call centers or more advanced digitally-enabled channels like mobile applications, social media and voice assist technologies. We have rolled out an advanced Interactive Voice Response (IVR) system and improved website capabilities as well as provided new payment options through mobile and social platforms, such as PayPal, so that we can meet the growing variety and individuality of customers' preferred channels, even those customers who do not have traditional bank accounts.

To meet these needs of our customers, a strong T&D system is essential. Over the past three years, we have invested heavily in needed pole and underground wire replacements that have come to the end of their useful lives, and we have made numerous substation upgrades to maintain reliability and address new and growing load.

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

A. Key drivers of this rate case reflect our customer's expectations, including investments we have made in our new Integrated Operations Center (IOC) – and the smart grid platforms it will house – the repowered Faraday Powerhouse, and our wildfire mitigation program. Most significantly, we have made investments in hundreds of individual projects, large and small, to modernize, strengthen, and upgrade our T&D system for customer growth, enhanced reliability, and resilience. The investments reflected in this rate case will meaningfully contribute to the realization of our strategy to deliver a clean and smart energy future while they also deliver value for our customers by creating a more flexible, reliable, resilient, secure, and integrated grid.

The foundation we are creating will allow deployment of new assets and technologies to securely integrate increasing volumes and types of distributed energy resources. These will provide both local and system-wide customer benefits, maximizing the contributions of flexible load programs and taking advantage of growing numbers of smart and connected customer end-use devices. Ultimately, these foundational investments will help us more rapidly advance decarbonization at a lower cost, while providing new and more compelling service options for customers.

Q. How do your customers' changing expectations influence the services PGE delivers and their associated costs?

A. Customers across the territory, from residential to large industrial, want to go cleaner faster while maintaining affordability. Municipal customers want to decarbonize their energy supply further and faster than the current Renewable Portfolio Standard prescribes, and we are working with them to develop more comprehensive clean energy options, like our recently launched Green Future Impact program. Residential and commercial customers are also looking for more renewable and carbon free options in their energy supply, and in some cases looking for ways to produce power and contribute to the grid themselves. Commercial and industrial customers are expressing urgency with respect to meeting their own climate and sustainability goals to meet their customer and stakeholder expectations and looking to PGE's energy supply to play a significant role in reducing the overall carbon footprint of their businesses. These customers are demanding both faster decarbonization of our supply and a broader and more customized range of alternatives to help them achieve their sustainability goals. Also as noted above, customers want PGE to be easy to do business with, because they seek to engage with us to find energy solutions – not just products – to meet their needs.

Consequently, we are increasing the number of channels we have available to engage with customers more effectively and meet them on their own terms. In addition, driven by the needs of our customers, state policy, and climate imperatives, we have added renewable and carbon-free generation of various types, scales and locations to our supply mix – like our triple-resource Wheatridge project – created additional green energy service options, deployed the smart grid test bed and expanded flexible load programs, and launched a variety of transportation electrification pilots and residential storage rebates.

In this rate case the IOC and the platforms and control systems it will house require a substantial investment on behalf of customers, in addition to the significant investments made in the grid itself. At the same time, over the long run the added flexibility, cleaner energy system and greater variety of energy solutions enabled by this newer, smarter, more reliable, and more resilient system also protects the affordability of electric service. As the electric power system begins to serve a larger share of customers' overall energy demand, the improved range of customized energy solutions and greater efficiency of this smarter system will yield benefits and increased value on both the grid level and the individual customer level

Q. Please provide additional detail on PGE's strategic investments.

A. The IOC is the single largest investment on behalf of customers in the rate case and supports safe grid operations, modernization, and decarbonization. In short, the IOC will allow PGE to efficiently control and monitor all elements of the integrated grid in a single facility, even under extreme conditions. As the nerve center of the smart grid, the IOC will be hardened against natural disasters, such as earthquakes, as well as physical and cyber threats, resulting in a more reliable delivery of electricity for our customers when faced with crises and in day-to-day operation or when faced with crises or events like winter storms or summer heatwaves. This investment in our future means greater reliability for customers with fewer and shorter outages, as it provides the foundation for an integrated grid with greater visibility and operational control over our T&D system and the ability to support future technologies and innovations without disruption. A detailed explanation of the role of the IOC is offered in PGE Exhibit 800.

In addition to the IOC, PGE has made significant investments in its T&D system to address increasing customers and electricity demand, safety and system hardening. These investments provide customers with safer and more reliable energy and are also described in greater detail in PGE Exhibit 800.

The rate case also includes the repowered Faraday Powerhouse on our Clackamas River Hydroelectric Project. The original powerhouse was one of PGE's earliest investments on customers' behalf, made in 1908. After more than a century of service, its replacement illustrates an important element of our clean energy strategy: We are building a new, modern facility with more efficient turbines.

Q. Please provide more detail regarding your grid modernization and decarbonization efforts.

A. PGE is implementing multiple projects as part of our grid modernization and decarbonization effort, including an Advanced Distribution Management System (ADMS), expansion of Dispatchable Standby Generation resources, enhanced Enterprise Data Analytics, and expansion of the Reliability Performance Monitoring Center to include T&D assets.

Each of these provides important value and benefits to customers, supporting our ability to deliver on our clean energy commitments through improved integration of carbon-free resources, and our ability to partner with customers and offer them more options and greater choice and control over how they use energy.

T&D systems are experiencing an evolving and growing interdependence due to the growth of customer-sited distributed energy resources like storage devices and flexible load and our increasing ability to directly monitor, control and optimize those resources. All these systems, resources and devices will be managed, monitored, and secured at the IOC, which will facilitate reliable and resilient system operations under varied and even extreme conditions, providing customers with both day-to-day value and just-in-case peace of mind for both natural and human-caused disasters.

As part of the IOC, we will deploy ADMS, a new software platform that will allow us to manage increased demand while integrating existing and new renewable resources. It will also enhance our integration and optimization of flexible loads (e.g., demand response resources), distributed energy resources, microgrids, energy storage and electric vehicles, all of which will help advance our decarbonization efforts. The platform supports the prediction, monitoring, control, optimization, and safe operation of all elements within a distribution system, which will enable us to proactively detect and respond to issues before they impact customers, helping to reduce outages. Additionally, the new technology will provide a self-healing capability for the grid, helping to further reduce outages and downtimes. ADMS functions are still being developed and expanded across the industry, but include fault location, isolation and restoration, volt/volt-ampere reactive optimization, and conservation voltage reduction. PGE Exhibit 800 also provides additional detail regarding ADMS.

Q. How does state policy fit into PGE's strategic vision?

A. PGE's strategic vision strongly aligns with the outcomes envisioned in the Governor's recent Executive Order 20-04 on Climate Action, which directs state agencies to take actions to reduce and regulate greenhouse gas emissions,[4] and in the 100% Clean Electricity law (House Bill 2021) recently passed by the Legislature.[5] Our strategy also furthers the state's transportation electrification policies articulated in Senate Bill (SB) 1547[6] and SB 1044,[7] and the recently enacted House Bill 2165.[8] In addition, we are leveraging new technologies that will maximize the value of our assets and productivity of our people, while driving costs out of our systems and processes. This will help us maintain affordability and reliability, as we deliver increased customer value through expanded platform capabilities that enable enhanced energy products and services and exceptional customer experiences.

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[4] https://www.oregon.gov/gov/Pages/carbonpolicy_climatechange.aspx
[5] https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[6] https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled
[7] https://olis.oregonlegislature.gov/liz/2019R1/Downloads/MeasureDocument/SB1044/Enrolled
[8] https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2165/Enrolled

It is also important to note that managing the increasing risks of wildfire is also reflected in both Executive Order 20-04 and in PGE's strategy. The adoption of new technologies for improved visibility, flexibility, and operational control of our T&D systems at our IOC will also play an important role in monitoring and helping to reduce the potential for wildfire-related impacts from our system.

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. The vertically integrated model is being leveraged by Oregon's key clean energy policies, the Renewable Portfolio Standard and the new 100% Clean Electricity law (HB 2021), to decarbonize the Oregon's electricity system at scale and at an accelerated pace, while keeping it affordable and reliable. To build the security, reliability, resiliency, and efficient integration of resources that customers need as we decarbonize consistent with these important policies, vertically integrated, fully regulated utilities like PGE will need to remain at the heart of the system. Placing the regulated utility at the center of the state's decarbonization strategy also allows public policymakers, regulators, and stakeholders to retain a strong voice in overseeing how that strategy is implemented. The integrated grid, with increasing diversity of resources, more distributed resources, and a greater range of customer options for interacting with the system has a critical role to play in helping to balance load and variable resources. These efforts will take Oregon further, faster if customers and the electric system remain integrated and coordinated. Increasing energy volumes and system scale also puts downward pressure on customer prices while maximizing the value of our collective decarbonization efforts.

When large nonresidential customers choose to purchase energy from an alternate electricity supplier, it is our obligation to protect all customers and ensure that customers departing PGE's supply service pay their fair share of system costs, including costs related to public policy directives and resource adequacy. In this rate case, we are proposing that the costs of two mandated state programs – the solar payment option (feed-in tariff) and demand response – are not bypassed when customers choose long-term and new load direct access. The non-bypassability pricing approach is discussed further in PGE Exhibit 1200, Pricing.

III. Price Increase

Q. Given the recognition of price affordability, please summarize PGE's request to the Commission.

A. We request that prices be adjusted to yield approximately $59.0 million in additional revenue, which represents a 2.9% increase in base rates beginning May 2022. PGE has separately requested a 2.0% increase in power costs as filed in PGE's annual update tariff (Docket No. UE 391), for a total revenue requirement increase of $99.0 million. These values are offset by a decrease of 0.9% related to supplemental schedules, and a decrease of 0.1% for cycle billing basis. This results in an all-in price change of 3.9% in 2022. Our last rate case was for 2019, making this our first base rate increase in over three years. The primary costs driving this increase, along with the impacts by customer class, are detailed in PGE Exhibits 200, Revenue Requirement, and PGE Exhibit 1200, Pricing.

Q. What are the primary elements of PGE's rate increase?

A. As discussed above, our request is centered on investments made to enhance reliability, safety, and efficient service as the basis for increased customer value as we transition to a clean energy system through the use of a more integrated grid. Consequently, most of the requested increase is based on capital expenditures and capital-related costs, the primary components of which are a significant number of T&D-related system modernization and resiliency projects, as well as strategically-focused projects such as the IOC and the repowered Faraday Powerhouse.

Q. What are the drivers behind the T&D capital investments made in this case?

A. The customer price increase in this case is being driven primarily by increases in T&D capital. From 2019 through April 30, 2022 we have or will have invested $1,566.3 million in T&D,

net of $119.2 million of depreciation in the areas shown in Table 1 below. These values include pole replacements, major system inspections and upgrades, customer driven projects, replacement of failed underground cables, replacement of unjacketed cable, and major upgrades to substations. For more details on these investments, please see PGE Exhibit 800.

Table 1
T&D Capital Additions
($millions)

Category	Additions
Poles & Wires	$ 809.1
Substations	$ 351.7
Integrated Operating Center (IOC)	$ 215.2
Line Transformers	$ 67.8
Meters Additions and Replacements	$ 53.5
Advanced Distribution Management Systems (ADMS)	$ 27.4
Field Voice Communications	$ 17.4
Field Area Network (FAN)	$ 16.2
Remote Sensing Project	$ 8.0
Gross Plant	**$ 1,566.3**
Net Plant*	**$ 1,447.1**

** Net of accumulated depreciation*

These projects benefit customers by maintaining and improving reliability and resiliency, and by addressing specific customer needs and customer load growth.

Q. What actions has PGE taken to mitigate the price increase in this rate case?

A. To mitigate the price increase while still allowing us to make essential system improvements, we have managed our operations and maintenance (O&M) costs carefully to keep the increase in O&M to a level well below the average rate of inflation. In addition, we modified our request as follows: 1) this case does not include any officer incentive compensation and we have removed 50% of all other forecasted incentive compensation costs; 2) we are not requesting an increase in the return on equity (ROE); and 3) we have maintained the uncollectibles rate approved in PGE's last general rate case, UE 335. Our proposal is to maintain PGE's ROE of 9.5%, despite support from our ROE witness that would justify a higher ROE rate, and a capital structure of 50% debt and 50% equity. The specifics regarding cost increases and the efforts to mitigate them are discussed in more detail in the testimonies addressing PGE's operations. We also honor our commitment to exclude all costs related to PGE's August 2020 trading losses.

Q. How does this rate case reflect your commitment to managing your costs?

A. This case reflects the savings achieved through our continuous improvement and operational planning efforts. Our commitment is to manage costs, streamline processes, learn from others, and maintain a culture of continuous improvement at PGE that benefits customers through improved service and reduced long-term cost impacts.

For example, over recent years, we have incorporated cloud-based services that provide us with a new level of flexibility in how we manage and organize our Information Technology (IT) capabilities. Using cloud-based services instead of traditional data center services provides more reliability, supports business continuity plans, and reduces IT costs. The use of this technology also increases efficiency and reduces enterprise risk, as well as increasing financial transparency and enabling more 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.

PGE has also realized efficiencies through renegotiating long-term service agreements, improving plant maintenance practices, improving line operations processes to decrease reliance on contractors, material cost reductions through supplier renegotiations and decreases to labor resources across the company. The testimonies discussing PGE's operations provide additional detail regarding efficiencies and savings achieved and incorporated in this filing.

Q. Has PGE protected customers from costs related to last summer's trading losses, in this rate case?

A. Yes. All costs attributable to the losses as well as the losses themselves are not included in this case and our intention is that customers will not bear any of them.

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

A. Yes. The results of this case, as filed, will provide PGE the opportunity to fund capital investments, meet financial obligations, and provide an opportunity for our shareholders to receive a reasonable return on their investment – which in turn benefits customers by giving investors an incentive to provide access to capital used to support reliable, affordable service to customers.

Q. Are there other risks of changes to PGE's requested price increase that are not currently factored into the costs for the 2022 test year filing?

A. Yes, given that the Oregon Legislature very recently adjourned, newly enacted laws will impact PGE's costs and revenue structures including laws that enable further decarbonization and transportation electrification, modify the public purpose charge framework, provide for differentiated rates for low-income customers, and establish wildfire protections, among others. We have developed the 2022 test year within the context of the current regulatory and statutory model and PGE operations within that model. As the case proceeds, we will work with parties as appropriate to update costs, revenues, and utility actions as necessary and appropriate.

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 our revenue requirement by $99.0 million and prices by 3.9%. The requested price increase is the combination of an approximate 2.0% increase in PGE's 2022 net variable power costs (requested in pending docket UE 391), offset by a 0.9% decrease in supplemental schedules, to be effective January 1, 2022, offset 0.1% when taking into consideration cycle billing, and an approximate 2.9% base business increase to be effective May 1, 2022. This request is discussed in more detail in PGE Exhibit 200, Revenue Requirement. In PGE Exhibit 1200, we provide information on 2022 supplemental schedules and their offsetting impact to the overall price increase for 2022.
- Include the IOC and other proposed capital additions in rate base. This request is discussed in more detail in PGE Exhibit 800, Transmission and Distribution.
- Accelerate Colstrip depreciation. This request is discussed in more detail in PGE Exhibit 200, Revenue Requirement and is reflected in the depreciation study filed in Docket UM 2152.
- Improve wind modeling within PGE's power cost forecast by updating the hourly price-shaping model, known as Lydia, to incorporate the effects of wind generation volatility on energy prices. This request is discussed in more detail in PGE Exhibit 100, Net Variable Power Costs, as filed on April 1, 2021, Docket No. UE 391.

- Modify PGE's Level III Outage Restoration mechanism to include a balancing account with sharing percentages. This request is discussed in more detail in PGE Exhibit 800, Transmission and Distribution.
- Adopt a non-bypassable rate spread method for the costs associated with state policy and state mandates tied to the Solar Payment Option cost recovery rate schedule. This request is discussed in more detail in PGE Exhibit 1200, Pricing.
- Change the residential customer basic charge to distinguish between those who live in multi-family and single-family dwellings to create more equitable residential customer pricing. The request is discussed in more detail in PGE Exhibit 1200, Pricing.

Q. How is PGE presenting this case?

A. We are presenting the following direct testimony:

- In Exhibit 200, Alex Tooman, Senior Regulatory Consultant, and Greg Batzler, Regulatory Consultant, summarize the overall $2,105.0 million test year revenue requirement, comparing the request with that most recently approved in our last general rate case UE 335 (2019 test year). In Exhibit 200, we identify a specific Colstrip revenue requirement and propose that all identifiable Colstrip-related costs be included in a separate tariff schedule. The revenue requirement of $2,105.0 million includes $55.9 million of Colstrip related capital and expense costs. This testimony also discusses our net rate base, plus associated depreciation and amortization expense, and unbundled results.
- In Exhibit 300, Anne Mersereau, Vice President, Human Resources, Diversity and Inclusion, and Tamara Neitzke, Director of Total Rewards, present total

compensation costs for the 2022 test year and describe how PGE's compensation philosophy is designed to address compensation challenges.

- In Exhibit 400, Jim Ajello, Chief Financial Officer, and Greg Batzler, Regulatory Consultant, explain PGE's request for administrative and general (A&G) costs in 2022.
- In Exhibit 500, Larry Bekkedahl, Senior Vice President of Grid Architecture, Integration, and System Operations, and John McFarland, Vice President and Chief Customer Officer, explain PGE's forecast of Customer Service O&M costs and address the Transportation Electrification program. They also discuss customer payment options and the proposal to offer fee free debit and credit card payments to small non-residential customers.
- In Exhibit 600, Jason Salmi Klotz, a Principal Product Development Specialist, discusses PGE's Flexible Load Plan and explains PGE's proposal for submitting a portfolio level, multi-year plan and cost recovery options to address that plan, later this year.
- In Exhibit 700, Bradley Jenkins, Vice President, Utility Operations, and Stefan Cristea, Sr. Regulatory Analyst explain the O&M expenses associated with PGE's long-term power supply resources. They also discuss the recent plant performance of our generation fleet.
- In Exhibit 800, Larry Bekkedahl, Senior Vice President of Grid Architecture, Integration, and System Operations, and Bradley Jenkins, Vice President of Utility Operations, discuss T&D capital expenditures from 2019 through April 2022 and incremental O&M costs for the 2022 test year. Their testimony includes a detailed

discussion of the IOC, ADMS, Wildfire Mitigation, Vegetation Management, and Level III storm restoration costs.

- In Exhibit 900, Jardon Jaramillo, Senior Director of Treasury, Investor Relations, and Risk Management, and Jaki Ferchland, Manager of Revenue Requirement in Regulatory Affairs, recommend our cost of capital and capital structure for the 2022 test year; and Bente Villadsen, economist and principal at The Brattle Group, estimates our required ROE and describes the supporting analyses.
- In Exhibit 1000, Amber Riter, Economist and Lead Load Forecasting Analyst, provides PGE's 2022 test year load and customer forecast.
- In Exhibit 1100, Robert Macfarlane, Manager, Pricing and Tariffs, and Christopher Pleasant, Senior Regulatory Analyst, describe the methodologies and results of PGE's generation, transmission, distribution, customer service, and street lighting marginal cost of service studies.
- In Exhibit 1200, Robert Macfarlane, Manager, Pricing and Tariffs, and Teresa Tang Regulatory Consultant, describe how the proposed tariff changes recover our 2022 revenue requirement to achieve fair, just, and reasonable prices for our customers and price changes to various supplemental schedules. They also discuss PGE's proposal to implement non-bypassability of costs associated with the state's solar payment option program, allocating costs to all customers.

Q. Has PGE submitted testimony regarding its power cost forecast?

A. Yes. As discussed above, PGE delayed the filing of this general rate case to help mitigate the price impact on customers. Because this filing is made on July 9, 2021, we submitted our initial filing for net variable power costs (NVPC) on April 1, in accordance with Commission

Order No. 07-015. In this proceeding we intend to include the value of NVPC, when appropriate, as updated and approved with UE 391.

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, 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 Oregon Global Warming Commission. My other board and commission activities include The Nature Conservancy, Edison Electric Institute, Electric Power Research Institute, and the Federal Reserve Bank of San Francisco. 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 394

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Alex Tooman, Ph.D.
Greg Batzler

July 9, 2021

Table of Contents

I. Introduction

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

A. My name is Alex Tooman. I am a Senior Regulatory Consultant for PGE. I am responsible for the development of PGE's revenue requirement forecast and other regulatory analyses.

My name is Greg Batzler. I am a Regulatory Consultant for PGE.

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 2022 test year forecast revenue requirement for the following components:

- Base business including Colstrip of $2,105.0 million; and
- Colstrip isolated revenue requirement of $55.9 million

As discussed in PGE Exhibit 1200, PGE proposes to isolate all identifiable Colstrip-related costs (both expense and capital related costs) to be included within a separate tariff schedule. As such, we provide here a Colstrip revenue requirement, which, after being included within the proposed separate schedule, would reduce our base business request for pricing purposes. Because the Colstrip tariff is effectively part of base rates, however, the following testimony will discuss PGE's 2022 revenue requirement with Colstrip unless specifically stated otherwise.

Q. What increase in revenue requirement does PGE request in this general rate case (GRC)?

A. In this filing, PGE requests an overall base business increase of approximately $59.0 million or 2.9%, including all Colstrip-related costs, which would become effective May 1, 2022. Combined with the approximate 2.0% increase for PGE's 2022 net variable power costs

(NVPC), which is currently requested in Docket No. UE 391 (PGE's 2022 Annual Update Tariff or AUT) and would become effective January 1, 2022, this results in a total increase in revenue requirement of approximately $99.0 million, or 4.9%.

The combined increase is relative to the revenues we expect based on: 1) 2019 prices approved in Public Utility Commission of Oregon (Commission or OPUC) Order No. 18-464 in Docket No. UE 335 (UE 335); plus 2) the 2021 power costs reflected in PGE Schedule 125; and 3) the Wheatridge facility costs reflected in PGE Schedule 122. The combined increase, however, is offset by a rate credit of approximately 1.0% in PGE's supplemental schedules, also effective January 1, 2022, for an overall net rate increase of 3.9%.

The revenue requirement proposed in this filing will allow PGE an opportunity to earn a 6.94% rate of return that includes a 9.50% return on average common equity (ROE) in 2022.[1] PGE Exhibit 201 summarizes the development of PGE's 2022 base business revenue requirement. In addition to presenting this integrated (bundled) revenue requirement, we also present and discuss PGE's unbundled revenue requirement in Section VII.

Q. In the absence of a price increase, what is PGE's expected regulated ROE for 2022?

A. Without a price increase, we would expect PGE's regulated ROE to be approximately 7.07% in 2022, which is significantly lower than the currently authorized ROE of 9.50%.

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

A. PGE's test year is calendar year 2022 and the base year of most recent actual results is 2020. Based on the filing date of this case, however, we propose a rate effective date of May 1, 2022. Further, given this effective date, we have established rate base as of April 30, 2022.

[1] As discussed in PGE Exhibit 900, PGE proposes a 50/50 capital structure between debt and equity.

This allows PGE to avoid used-and-useful issues regarding plant in service and prices while using the most up-to-date information to establish rate base for the test year.

Q. Does PGE's 2022 revenue requirement include any amount related to the energy trading losses that occurred during the third quarter of 2020, or any subsequent costs associated with those losses?

A. No. PGE is not pursuing regulatory recovery for amounts related to the 2020 trading losses, and no associated costs have been included in the 2022 test year revenue requirement. In particular, we adjusted PGE's accumulated deferred income taxes (ADIT) downward by approximately $18.4 million, thus reducing rate base by that amount. This amount represents the value of production tax credits (PTCs) that would have been used had PGE's net income not been reduced due to the trading losses. In addition, PGE no longer has any net market exposure from the energy trading positions that led to the previously announced losses.

Q. Does PGE's 2022 revenue requirement include any costs associated with the Boardman generating plant?

A. No. PGE's Boardman plant ceased operations in the fourth quarter of 2020. Consequently, no Boardman operation and maintenance (O&M) or plant-related costs are included in PGE's 2022 revenue requirement. PGE Exhibit 700 provides additional information on O&M cost updates including the impact of the Boardman plant shut down.

Q. What mitigating actions did PGE take to limit the size of the requested increase in this filing?

A. As our customers are recovering from the economic dislocation of the COVID-19 pandemic, PGE has worked to manage costs and offset the impacts of inflation and other prudent cost increases reflected in this case. To accomplish this, PGE has taken a number of specific actions including:

- Removing 100% of all forecasted Officer incentive costs and 50% of all other 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;
- Even though cost of capital is increasing, maintaining an ROE and capital structure at the current levels authorized in Order No. 18-464 (UE 335) and proposing only to update PGE's cost of debt to reflect lower costs;
- Maintaining the 0.32635% uncollectibles rate approved in PGE's most recent general rate case (UE 335);
- Removing $1.0 million of meals and entertainment costs based on 50% of the three-year-historical average for these costs, even though these costs are typical prudent business expenditures, included in previous general rate cases, and appropriate for recovery;
- 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; and
- Incorporating forecasted efficiencies and O&M cost savings through our rigorous operational planning and budget process.

Q. What O&M savings has PGE included in budgets and forecast submitted with this case?

A. Examples of the identified budget savings, which hold overall O&M increases below the current rate of inflation, are included in the testimonies addressing PGE's operations. This builds on the significant detail provided in prior general rate cases, including UE 335, to quantify benefits to customers for the programs, systems, and initiatives being implemented by PGE. The efficiencies and savings identified through PGE's annual operational planning process, have also resulted in additional O&M budget reductions between 2020 and the test year.

A. Summary of the Case

Q. Please summarize PGE's 2022 revenue requirement.

A. Table 1 below summarizes PGE's 2022 revenue requirement by major category, including an isolated Colstrip revenue requirement, and provides a comparison to the results of UE 335. We also list the PGE testimony that addresses each specific cost category.

Table 1
Revenue Requirement Summary
($millions)

Rev Req Category	UE 335 Approved	2022 Total Forecast	2022 Colstrip	2022 Net of Colstrip*	Exhibit	No.
Sales to Consumers	$ 1,831.4	$ 2,105.0	$ 55.9	$ 2,049.1	Rev Req	200
Other Revenue	25.3	29.3	2.8	26.5	Rev Req	200
NVPC	361.5	511.8	-	511.8	Rev Req	200
Production O&M	164.0	126.1	14.9	111.1	Production	700
Transmission O&M	15.8	19.9	0.4	19.5	T&D	800
Distribution O&M	135.3	152.8	-	152.8	T&D	800
Customer Service	82.3	90.0	0.2	89.8	Customer Svc.	500
A&G	164.6	186.9	2.4	184.4	Corp. Support	400
Depr. & Amort.	369.0	398.5	23.7	374.7	Rev Req	200
Other Taxes	137.2	157.1	6.3	150.7	Rev Req	200
Income Taxes	80.5	93.5	1.3	92.3	Rev Req	200
Operating Income*	**$ 346.4**	**$ 398.0**	**$ 9.5**	**$ 388.5**		
Return on Equity	9.5%	9.5%	9.5%	9.5%	ROE	900

** 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 900.

Q. How did you develop the 2022 revenue requirement?

A. We developed the revenue requirement based on PGE's 2021 budgets, which were originally based on a 2020 budget that reflected Commission Order No. 18-464 for 2019 prices. The 2021 budgets were escalated for inflation to 2022 and adjusted for known and measurable changes.

Q. How did you escalate the 2021 budget to 2022 test year?

A. We applied the following escalation rates to the 2021 budget:

- 3.17% average rate for all labor (at applicable effective dates[2]);
- 2.88% for contract labor and outside services (cost elements [CE] 1502, 1602, 2200, and 2300), effective January 1;
- 1.36% for direct materials (CE 2101 and 2110), effective January 1; and
- 2.09% 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 February 2021. Wage escalation is based on the forecast of compensation costs as described in PGE Exhibit 300.

Q. In explaining cost changes for test year 2022, what base year does PGE generally reference?

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

A. In the testimonies that discuss O&M, Customer Service, and Administrative and General (A&G) costs, we compare our 2022 test year forecast to the 2020 base year. We do this because 2020 represents PGE's most recent full year with actual results. The changes between 2020 and 2022 in this filing will be analyzed on an average annual basis.

Q. Did you adjust PGE's 2022 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	$ (0.2)	$ (0.7)
Charitable Contributions	(2.3)	
State & Federal Lobbying	(1.3)	
MDCP	(3.3)	
SERP	(1.2)	
Image Advertising	(1.2)	
Total Adjustments*	**$ (9.6)**	**$ (0.7)**

**** 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 $2.3 million from cost of service;
- State and federal lobbying: excluded the entire $1.3 million from cost of service;
- Management Deferred Compensation Plan (MDCP): removed the entire $3.3 million from cost of service;
- Supplemental Executive Retirement Plan (SERP): removed the entire $1.2 million from cost of service; and
- Corporate image advertising: removed the entire $1.2 million from cost of service.

II. Other Revenue

Q. What is PGE's 2022 forecast of Other Revenue?

A. PGE forecasts 2022 Other Revenue of $29.3 million. This compares to actual 2020 Other Revenue of $32.2 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 2022 test year?

A. Yes. We added approximately $0.75 million for fees collected for Green Power Administration and Green Tariff Administration to avoid double collecting these costs.

Q. Did you include any revenue associated with the Salmon Springs Hospitality Group?

A. No. Because of the COVID lockdowns in 2020 and 2021, PGE ceased operations of its catering facilities for the 2 World Trade Center. At this time, PGE has no plans to re-establish this activity.

Q. Why did Other Revenue decrease from 2020 actuals to the 2022 Forecast?

A. This apparent reduction is primarily due to certain revenue being recorded to Other Revenue in 2019 and 2020 that offsets expenses PGE incurred during the same period to provide project support for a third-party accessing PGE equipment. Because of the temporary and uncertain nature of these costs and revenues, neither have been forecasted for 2022. This is partially offset by increases in late payment fees and miscellaneous service revenues that declined in 2020 due to COVID restrictions[3] but are forecast at more typical levels in 2022.

[3] As specified by Commission Order No. 20-401 (Docket No. UM 2114).

Q. Is it possible that the Commission could revise certain rules pertaining to late payment fees and other credit and connection policies, which might require a reexamination of your forecast?

A. Yes. The Commission has provided direction to the OPUC Staff to investigate changes in credit and connection policies, and Staff is expected to provide recommendations before the end of 2021. Those recommendations could necessitate a reconsideration of PGE's 2022 forecast of applicable items in Other Revenue.

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

A. No. PGE is considering filing a transmission rate case (TRC) with the Federal Energy Regulatory Commission (FERC), but we have not included any impact from that case in the revenue requirement for this GRC.

Q. Please explain why you have not included such an update.

A. Although we are considering filing a TRC to establish wholesale transmission rates based on a 2022 test year forecast, similar to the GRC, the timing of these cases would not coincide. More specifically, the GRC will have been filed in early July 2021, but the potential TRC first had to wait until after PGE's 2020 FERC Form 1 was submitted in April 2021,[4] and then we would have to assemble the TRC while we are in the midst of the GRC, relying on many of the same PGE staff. We also note that there is a substantial learning curve to file a TRC.[5] In summary, by the time all rounds of testimony are complete in this GRC, PGE will at best have TRC amounts that only represent an initial filing position. Because TRCs require months of

[4] TRCs are based on an actual Period 1 (for comparison purposes) and a forecast Period 2 on which to base prices. For PGE's TRC, Period 1 will be based on the 2020 FERC Form 1, and Period 2 will be based on the 2022 forecast.
[5] PGE's previous TRC dates back to 2001.

process, as do GRCs, even if we were to file the TRC later in 2021, we would not expect a FERC order on PGE's rates until well into 2022, at which time they would apply retroactively based on FERC's statutory timeline.[6]

Q. How do you plan to provide customers with the benefit of the updated OATT rates?

A. In Docket No. UM 2031,[7] Commission Order No. 19-400 adopted a stipulation that stated (see page 5):

> The stipulating parties acknowledge that alignment of cost recovery with the reclassification will require a transmission rate case at FERC and a general rate case at the Commission. The stipulating parties state that if a timing mismatch occurs between the rate effective dates of those proceedings, certain customers, including direct access customers may pay for service under the 115 kV facilities in both distribution and transmission rates. Under the stipulation, PGE commits to propose a method to hold all customer classes harmless, preventing double recovery, for the time between the rate effective date in FERC and Commission rate cases including the reclassified assets, in the event such a timing mismatch occurs. Further, under the stipulation, Staff, CUB, and AWEC agree to support PGE's efforts to develop this method and obtain Commission approval, recognizing that any such mechanism would be subject to Commission approval.

Q. Based on this agreement and order, does PGE have a proposal in this case?

A. Yes. PGE requests that the Commission authorize a deferral of all incremental revenue associated with the final FERC-approved rates including, as applicable, those associated with line losses. In addition, we propose that the deferral would: 1) be subject to an automatic adjustment clause; 2) be effective as specified in the applicable FERC order; and 3) continue until PGE's next GRC (with the deferral to be re-authorized annually), at which time we will incorporate the updated transmission revenue in the forecast for Other Revenue.

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[6] FERC rates typically go into effect five months after they are filed. These rates are subject to refund based on the final rates approved by the FERC after hearing and settlement discussions have concluded.

[7] PGE's request for Commission support of its proposal to reclassify certain facilities from distribution to transmission.

III. Depreciation

Q. What is the basis for the 2022 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 ADIT. Because PGE established its rate base as of April 30, 2022, we used depreciation through this date in the calculation of all four items.

Q. Does this depreciation accurately reflect the 2022 expense?

A. By itself, no. Because this depreciation will only reflect partial year depreciation for 2021 plant closings,[8] that depreciation will be less than full 2022 depreciation, which will reflect a full year of depreciation for those same assets. To adjust for this effect, PGE annualized the 2021 depreciation expense for 2021 plant closings and then reduced that amount to account for the annualized effect of declining depreciable base in prior vintages. In summary, the 2021 depreciation expense is annualized and adjusted so that PGE does not under-collect or over-collect depreciation expense relative to expected 2022 depreciation expense. Depreciation for the period January through April 2022 is not annualized or adjusted since it directly applies to the test period. For simplicity, we refer to the test year depreciation as 2022 depreciation expense.

Q. What is PGE's estimate for 2022 depreciation expense?

A. We estimate $338.7 million in depreciation expense for 2022. PGE Exhibit 203 summarizes the 2022 depreciation expense by plant type and provides a comparison to 2020 actuals.

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[8] "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 new depreciation rates as part of this rate case?

A. Yes. PGE filed a new depreciation study on January 22, 2021 in Docket No. UM 2152 and proposes to reflect updated depreciation rates in this case.

Q. What is the difference between the previously approved depreciation study (Docket No. UM 1809, Order No. 17-365) and the current depreciation study (Docket No. UM 2152) for 2022 depreciation expense?

A. The methodology proposed in the current depreciation study leads to a $4.5 million decrease in depreciation expense for the plant in service included in our test year rate base.

Q. How does PGE's 2022 depreciation expense forecast compare to 2020 actuals?

A. After adjustments, total forecasted depreciation for 2022 reflects a $14.1 million increase over 2020 actuals.

Q. What are the primary drivers for the increase?

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

- $15.0 million for transmission and distribution facilities;
- $11.3 million for the Colstrip generation plant to reflect the change of depreciable life from the year 2030 to 2027 as specified in PGE's depreciation study filed in Docket UM 2152;
- $8.1 million for general plant including the addition of the new Integrated Operations Center (IOC);
- $6.2 million for hydro generation resources, thermal plants, and solar; and
- $5.3 million for the Wheatridge wind generation plant, which was placed in-service in December 2020. Customer prices, however, already reflect the full year of the

Wheatridge revenue requirement, including depreciation expense, in accordance with Commission Order No. 20-279.

These increases are partially offset by:

- $28.9 million reduction for the retirement of the Boardman generating plant in Q4 2020; and
- $6.6 million reduction in Biglow and Tucannon wind generation resources.

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 IRS tax normalization principles, we calculated the 2022 test year amortization expense similar to depreciation.

Q. Please summarize PGE's 2022 amortization expense.

A. PGE Exhibit 204 details the total 2022 amortization expense of $59.8 million, which we summarize in Table 3 below.

Table 3
Amortization Expense
($millions)

Category	**2020 Actuals**	**2022 Forecast**
Software Amortization 5-10 years	$ 58.9	$ 54.8
Other Intangible Amortization	3.8	3.6
Trojan Decommissioning	1.8	1.9
Regulatory Credits		(0.5)
Total Amortization*	**$ 64.4**	**$ 59.7**

** 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 2022 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 2022 amortization expense.

A. Total software amortization is approximately $54.8 million. This cost relates to capitalized software, which is typically amortized over a 5-year period, with the exception of larger software programs, which are amortized over a 10-year period. Examples of these larger software programs are the 2020 Vision programs, which included the new customer information system, meter data management system, the Finance and Supply Chain Replacement project (FSRP), and Maximo Mobile Scheduling.

Q. Why is software amortization approximately $4.1 million lower in 2022 compared to 2020?

A. The decrease is primarily due to the roll-off of software investment in 2021, the main component of which is the FSRP systems implemented in 2011. This is partially offset by software investment that closed to plant during 2020, resulting in partial year amortization in 2020, but full year amortization in 2021.

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, 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.

V. Income Taxes and Taxes Other Than Income

A. Income Taxes

Q. What is PGE's 2022 estimate of income taxes?

A. PGE's 2022 test year forecast for income tax expense is $93.5 million. This compares to the 2019 utility income tax expense of $80.5 million based on prices approved by Commission Order No. 18-464 in UE 335. PGE Exhibit 205 provides details on the test year calculations of income tax expense plus a comparison to previously authorized 2019 income tax assumptions.

Q. What method did you use to establish estimated income tax expense for the 2022 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.

Q. What marginal tax rates have you incorporated into your 2022 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 7.5943%. The rate is a function of the marginal state tax rates and the respective apportionment factors of taxable income to different state and local jurisdictions.

Q. Did you include the Oregon Corporate Activities Tax (OCAT) in the state and local tax rate?

A. No. We did not include the OCAT in this GRC because PGE has not yet filed a return for the tax, and thus, PGE has too little experience with the tax to determine a forecast amount for the 2022 test year. In short, PGE needs additional time to evaluate how the tax operates, how much expense it will generate, and how much variability it will entail before including OCAT in a GRC. Consequently, PGE proposes to continue to defer the OCAT as part of Docket No. UM 2037 until a future GRC.

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

A. PGE's total composite tax rate for this filing is 26.9995%, 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:

$$21.00\% + 7.5943\% - ((21.00\% * 7.5943\%) = 26.9995\%$$

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 to comply with OAR 860-022-0045. In addition, PGE has an approved deferral (Order No. 21-029; Docket No. UM 2131) and has filed for a corresponding tariff to address the Metro Supportive Housing Services Tax. Because this tax applies to only a portion of PGE's customers, the deferral and tariff will operate in the same manner as the MCBIT deferral (Docket No. UM 1986) and tariff. 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 2022?

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."[9]
- A federal credit of approximately $9.2 million to reflect the average rate assumption method of amortizing excess deferred federal income taxes.[10]

Q. Did you include any PTCs in your estimate of income tax expense for 2022?

A. Not in this filing because, 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 AUT filing.

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

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

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).

Q. Has PGE included any adjustment to its projected test year income taxes based on proposed federal tax legislation?

A. No. Although the federal government is considering income tax legislation for 2022, we will not have specific details about the changes or the impacts unless and until legislation is enacted. We do, however, propose that if the legislation is enacted during the pendency of this rate case proceeding, that PGE be allowed to incorporate reasonable forecasted 2022 impacts into base rates, as any such tax change would be permanent, in order to reflect a more appropriate estimate of the revenue requirement to serve customers, just as the Commission incorporated the impacts of the Tax Cut and Jobs Act into PGE's base rates in our last GRC.

B. Taxes Other than Income

Q. What is PGE's 2022 estimate of Taxes Other Than Income?

A. As shown in PGE Exhibit 206, total Taxes Other Than Income are $157.1 million for 2022. This compares to 2020 actual costs of $136.4 million. The primary cost changes from 2020 actuals to the 2022 test year are:

- Property Taxes: from $73.3 million to $83.8 million;
- Franchise Fees: from $46.0 million to $53.8 million; and
- Payroll Taxes: from $14.6 million to $16.5 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 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 property tax abatement agreements, which significantly reduces taxes for a 15-year period beginning in 2008 for Biglow Canyon, 2015 for Port Westward II, 2017 for Carty, and 2021 for Wheatridge.

Q. What is PGE's forecast for 2022 property tax expense?

A. PGE has forecast approximately $83.8 million of 2022 property taxes compared to 2020 actuals of $73.3 million.

Q. Why are property taxes increasing from 2020 to the 2022 test year?

A. Oregon property tax expense increases by $10.5 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 addition of the Wheatridge wind generation plant and the IOC. This is slightly offset by a decrease in Washington property taxes of approximately $0.2 million, due to decreases in net plant assets.

2. Franchise Fees

Q. Why have franchise fees increased from 2019 to the 2022 test year?

A. PGE updated the franchise fee rate to reflect the three-year average of 2018-2020 actuals. Although this represents a minimal increase in the franchise fee rate from 2.538% in 2019 (UE 335) to 2.556% in 2022, 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 8.0% 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 2020 to the 2022 test year?

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

VI. Rate Base

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

A. As discussed in Section I, PGE established its rate base balances as of April 30, 2022, and forecasts the total balance to be approximately $5,737.5 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 335?

A. PGE Exhibit 208 shows that the rate base approved in UE 335 is $4,744.7 million and that PGE's April 30, 2022 rate base reflects an increase of $992.8 million. The increase is primarily attributable to the growth in distribution plant, including the IOC as discussed in PGE Exhibit 800, as well as the Wheatridge wind generation plant and Faraday Repower Project as discussed in PGE Exhibit 700.

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 3.827% in 2019 (UE 335) to 4.216% in 2022. Applying the 4.216% Working Cash factor to total forecasted operating expenses in 2022 of $1,736.3 million produces the Working Cash total in rate base of approximately $73.2 million.

Q. Did PGE make an adjustment to rate base associated with the energy trading losses that occurred in August 2020?

A. Yes. As noted in Section 1, above, we adjusted ADIT downward by $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 trading loss. 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 closed to plant (see footnote no. 8, above).

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: land purchases, 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 2022 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 2022.

Table 4
Unbundled Revenue Requirement
($millions)

Production	$ 1,117.8
Transmission	87.2
Distribution	723.5
Ancillary	5.1
Metering	6.2
Billing	37.8
Other Consumer Services	127.4
Total*	**$ 2,105.0**

** 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 2022 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. Dr. Tooman, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting and Finance from the Ohio State University. I received a Master of Arts degree in Economics and a Ph.D. in Economics from the University of Tennessee. I have held managerial accounting positions in a variety of industries and have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. Finally, I have worked for PGE in the Rates and Regulatory Affairs department since 1996.

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. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
201	2022 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	Unbundled Results Summary

PGE
UE 394
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		4.93%
2				
3	Sales to Consumers (Rev. Req.)	2,006,036	98,967	2,105,003
4	Other Revenue Detail	29,346	-	29,346
5	Total Operating Revenue	2,035,381	98,967	2,134,349
6				
7	Operation & Maintenance	-	-	-
8	Net Variable Power Cost	511,766	-	511,766
9	Production O&M	103,238	-	103,238
10	Power Operations	22,830	-	22,830
11	Trojan O&M	93	-	93
12	Transmission O&M	19,874	-	19,874
13	Distribution O&M	152,769	-	152,769
14	Operations O&M	298,804		298,804
15	Customer Accounts	60,354	-	60,354
16	Customer Service	22,731	-	22,731
17	Uncollectibles Expense	6,547	323	6,870
18	OPUC Fees	8,135	401	8,537
19	A&G, Ins/Bene., & Gen. Plant	178,231	-	178,231
20	Support O&M	275,998	724	276,722
21	Total Operating & Maintenance	1,086,568	724	1,087,292
22				
23	Depreciation	338,741	-	338,741
24	Amortization	59,713	-	59,713
25	Property Tax	83,814	-	83,814
26	Payroll Tax	16,503	-	16,503
27	Other Taxes	2,935	-	2,935
28	Franchise Fees	51,271	2,529	53,800
29	Utility Income Tax	67,679	25,835	93,513
30	Total Operating Expenses & TOTI	1,707,222	29,089	1,736,311
31				
32	Utility Operating Income	328,159	69,878	398,038
33				
34	**Rate of Return**	5.721%		6.938%
35	*Weighted Cost of Debt*	2.188%	2.188%	2.188%
36	*Weighted Cost of Preferred*			
37	*Equity Share of Cap Structure*	50.000%	50.000%	50.000%
38	**Return on Equity**	7.067%		9.500%
39				
40	**Rate Base**	-	-	-
41	Gross Plant	11,630,140	-	11,630,140
42	Accum. Deprec. / Amort	(5,284,044)	-	(5,284,044)
43	Accum. Def Tax	(681,954)	-	(681,954)
44	Net Utility Plant	5,664,142		5,664,142
45				
46	Operating Materials & Fuel	67,724	-	67,724
47	Misc. Deferred Credits	(73,887)	-	(73,887)
48	Misc. Deferred Debits	6,294	-	6,294
49	Working Cash	71,984	1,227	73,210
50	Total Rate Base	5,736,257	1,227	5,737,484
51				

PGE
UE 394
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
52	Income Tax Calculations	-	-	-
53	Book Revenues	2,035,381	98,967	2,134,349
54	Book Expenses	1,639,544	3,254	1,642,797
55	Interest Expense	125,481	27	125,507
56	Permanent M Differences	(14,248)	-	(14,248)
57	Temporary Sch M Differences	154,217	-	154,217
58	State Taxable Income	130,389	95,687	226,075
59				
60	State Income Tax	9,902	7,240	17,142
61				
62	Federal Taxable Income	120,486	88,447	208,933
63				
64	Federal Tax	25,304	18,500	43,804
65				
66	Deferred Taxes	41,638	-	41,638
67	Excess Deferred Income Tax Reversal (ARAM	(9,156)	-	(9,156)
68	Total Income Tax	67,689	25,740	93,428

PGE
UE 394
Exhibit 201
Capital Structure / Revenue Sensitive Costs

Line No.	Rates	Dec - 2022
1	% R&D per UE 335	0.9097%
2	California State Income Tax - Appor	3.2991%
3	California State Income Tax - Rate	8.8400%
4	California State Income Tax - Weighted	0.2916%
5	Common Equity - Cost	9.5000%
6	Common Equity - Share	50.0000%
7	Common Equity - Weighted	4.7500%
8	Composite Tax Rate	26.9995%
9	Factor per OAR	0.1250%
10	Fed Tax	21.0000%
11	Federal Tax @ 21.000%	18.7672%
12	Federal Taxable Inc.	89.3676%
13	Franchise Fees	2.5558%
14	Gross-Up Factor	1.3699
15	Long-Term Debt - Cost	4.375%
16	Long-Term Debt - Share	50.000%
17	Long-Term Debt - Weighted	2.188%
18	Montana State Income Tax - Appor	2.4299%
19	Montana State Income Tax - Rate	6.7500%
20	Montana State Income Tax - Weighted	0.1640%
21	Net To Gross Factor	141.6422%
22	O&M Uncollectibles	0.3264%
23	OPUC Fees	0.4055%
24	Oregon Benefit of Local Tax deduction	(0.0014%)
25	Oregon State Income Tax - Appor	93.7021%
26	Oregon State Income Tax - Rate	7.6000%
27	Oregon State Income Tax - Weighted	7.1214%
28	Portland Local Income Tax - Appor	0.7208%
29	Portland Local Income Tax - Rate	2.6000%
30	Portland Local Income Tax - Weighted Plus B	0.0173%
31	Portland Local Income Tax - Weighted Pre Be	(0.0187%)
32	Revenues	100.0000%
33	RSC Gross-Up Factor	1.0340

34	State and Local Tax @ Present Rate	7.3446%
35	State and Local Tax Rate - Weighted	7.5943%
36	State Taxable Income	96.7123%
37	Tax Shield	(1.5948%)
38	Total Income Taxes	26.1119%
39	Total Rev. Sensitive Costs	29.3996%
40	Utility Operating Income	70.6004%
41	Working Cash Factor	4.2164%
42	Capital Structure Total	6.938%

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UE 394
Exhibit 202
Other Revenue Detail
Not Scaled

Line No.	Account	a-Dec - 2018	a-Dec - 2019	a-Dec - 2020	Dec - 2021	Dec - 2022
1	4470003: SalesfrResale-IntertiePGEtoPGE	(6,946,711)	(7,312,968)	(7,067,265)	(7,180,000)	(7,180,000)
2	4500001: Forefeited Discounts	(6,004,495)	(7,533,569)	(1,510,490)	-	(4,191,873)
3	4510001: Miscellaneous Service Revenues	(1,193,165)	(1,918,764)	(917,276)	(1,155,502)	(2,096,529)
4	4530001: Sales of Water & Water Power	11,415	25,668	20,340	-	-
5	4540001: Rent From Electric Property	(1,714,801)	(1,271,846)	(1,453,820)	(1,203,984)	(1,204,074)
6	4540002: RentFrElecProperty-Joint Pole	(7,374,023)	(10,582,480)	(12,375,540)	(13,294,368)	(13,294,368)
7	4560001: Other Electric Revenues	(4,699,484)	(7,581,609)	(7,028,841)	1,479,157	(1,191,300)
8	4560002: OthElecRev-RegulatoryDeferRev	2,075,290	43,063	3,252,694	1,158,780	4,763,984
9	4560003: OthElecRev-FishWildlifeRecrOps	(12,311)	(13,829)	(16,397)	-	(12,757)
	4560004: OthElecRev-SSHG	(239,360)	(69,475)	(90,983)	(120,301)	
10	4560005: OthElecRev-Utility Non-Kwh	(5,489)	(8,616)	(22,251)	-	-
11	4560012: OthElecRev-Steam Sales	(2,160,358)	(1,874,091)	(1,419,239)	(1,915,238)	(1,915,238)
12	4561001: TransRevOthers-Non-Intertie	(3,518,555)	(3,412,285)	(3,659,943)	(3,559,000)	(3,531,415)
13	4561002: TransRevOthers-Intertie	(7,042,193)	(7,026,637)	(6,945,362)	(6,672,000)	(6,672,000)
14	5660002: TransOp-MiscExp-IntertieWhePGE	6,946,711	7,312,968	7,067,265	7,180,000	7,180,000
15	Total	(31,877,530)	(41,224,471)	(32,167,108)	(25,282,456)	(29,345,569)

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UE 394
Exhibit 203
Depreciation Detail
Scaled (Thousands)

Line No.	Property Group	Dec - 2018	Dec - 2019	Dec - 2020	2021 Budget	**2021 Forecast used for 2022 Test Year**
		(1)	(2)	(3)	(4)	(5)
1	Boardman	28,811	29,123	28,934	-	-
2	Colstrip	10,789	11,493	12,450	14,450	23,714
3	Beaver	7,399	7,165	7,142	7,269	7,375
4	Biglow Canyon	32,733	31,550	30,315	29,117	25,474
5	Carty	13,112	12,762	12,404	12,143	12,218
6	Coyote Springs	4,957	4,992	4,775	4,595	4,490
7	DSG	331	350	348	363	346
8	Port Westward	8,160	8,065	7,959	7,776	7,427
9	Port Westward 2	7,655	7,484	7,308	7,267	7,298
10	Solar	142	161	142	155	141
11	Tucannon	15,767	15,240	14,771	14,299	13,003
12	Wheatridge				5,579	5,331
13	Hydro	21,098	22,095	22,253	24,217	29,234
14	Transmission	12,226	12,527	17,912	19,190	22,512
15	Distribution	106,818	118,179	120,970	132,094	131,381
16	General Plant	37,876	39,967	40,786	46,158	48,875
17	**Total**	**307,876**	**321,156**	**328,470**	**324,673**	**338,819**
18	Remove Boardman Decommissioning	(4,225)	(3,917)	(3,851)	-	-
19	Retail Adjustment	-	-	-	-	(79)
20	**Adjusted Total**	**303,651**	**317,239**	**324,620**	**324,673**	**338,741**

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UE 394
Exhibit 204
Amortization Detail
Scaled (Thousands)

Line No.	Item	FERC Account	AWO	Dec - 2018	Dec - 2019	Dec - 2020	2021 Budget	2021 Forecast used for 2022 Test Year
				(1)	(2)	(3)	(4)	(5)
1	Software Amortization (Intangible)	404	N/A	50,245	53,663	56,843	58,469	54,805
2	Other Intangible Plant (Includes Hydro Relicensing)	404	N/A	8,727	10,743	5,813	4,084	3,642
3	Amort Of UnrecvPlt-Troj Decomm	407	N/A	3,500	1,900	1,900	1,900	1,900
4	Amort Of UnrecvPlt-Troj Decomm	407	Troj Spent Fuel Settlement	(2,163)	(2,954)	(148)	-	-
5	Sunway 3	407.4	N/A	(45)	(45)	(45)	(45)	(45)
6	Amort. Incentive Reg. Liability (UE 283, S-17)	407.4	N/A	-	-	-	-	(500)
7				60,264	63,307	64,363	64,407	59,802
8	Allocated to Retail		N/A	-	-	-	-	(88)
9			Total	**60,264**	**63,307**	**64,363**	**64,407**	**59,713**

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UE 394
Exhibit 205
Income Tax Summary
Scaled (Thousands)

Line No.	Line	UE 335 2019 Test Year		2022 Test Year
1	Book Revenues	1,856,708		2,134,349
2	Book Expenses (including Depreciation)	1,429,801		1,642,797
3	Interest Deduction	120,990		125,507
4	Book Taxable Income	305,916.989		366,044
5	Production Deduction			
6	Permanent Sch. M	(22,629)		(14,248)
7	Temporary Sch. M	63,378		154,217
8	Taxable Income	265,168		226,075
9				
10	Current State Taxes	20,099		17,141
11	State Tax Credits	(10)		(10)
12	Net State Income Tax	20,089		17,131
13				
14	Federal Taxable Income	245,079		208,944
15				
16	Current Federal Taxes	51,464		43,802
17				
18	Federal Tax Credits			
19	ITC Amortization	(8,115)		(9,156)
20	Deferred Taxes	17,105		41,638
21				
22	Total Income Tax	80,543		93,415
23	Effective Tax Rate	26.33%		25.52%
24	Regulated Net Income			272,548
	Change in Taxes			12,872
	Analysis of Tax Change:			
	Effective Tax Rate Change			-0.81%
	Book Taxable Income (UE 335)			305,917
	Decrease in Taxes Due to Lower Effective Rate			(2,473)
	Change in Book Taxable Income (2019 vs UE 319)			60,127
	2019 Effective Tax Rate			25.52%
	Decrease in Taxes Due to Lower Book Taxable Income			15,344
	Sum of Tax Impacts			12,872

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UE 394
Exhibit 206
Taxes Other Than Income
Not Scaled

Line No.	Item	FERC	Account	Dec - 2018	Dec - 2019	Dec - 2020	Dec - 2021	Dec - 2022
1	Payroll Taxes	408.1	4081004: Payroll Taxes - FICA	24,006,868	25,621,265	24,636,475	25,891,392	26,894,926
2	Payroll Taxes	408.1	4081005: Payroll Taxes - Fed Unemploy	148,484	153,504	66,998	140,704	114,968
3	Payroll Taxes	408.1	4081006: Payroll Taxes - Trimet	1,878,585	1,916,045	2,120,589	1,868,376	1,984,065
4	Payroll Taxes	408.1	4081007: Payroll Taxes - State Umemploy	1,360,595	2,089,100	1,428,468	1,700,117	1,639,735
5	Payroll Taxes	408.1	4081008: Payroll Taxes - Worker's Comp	160,389	103,101	403,597	-	-
6	Payroll Taxes	408.1	4081009: AllocCredit - Payroll Tax	(12,264,259)	(13,532,053)	(14,103,257)	(12,799,305)	(14,131,079)
7	Property Taxes - Oregon	408.1	4081001: TaxOthThan IncTax-PropTax-Oreg	56,104,343	60,008,742	65,141,570	71,718,831	75,748,943
8	Property Taxes - Oregon	547	5470183: OthGenOp-CapLseFuel-UPropTaxOr	717,321	-	-	-	-
9	Property Taxes - Washington	408.1	4081002: TaxOthThan IncTax-PropTax-Wash	2,199,635	2,579,038	2,220,400	2,858,736	2,017,128
10	Property Taxes - Montana	408.1	4081003: TaxOthThan IncTax-PropTax-MT	5,431,376	5,584,756	5,954,440	5,576,100	6,047,784
11	Franchise Fees	408.1	4081010: TaxOthThanIncTax-FranFeePort	14,538,518	14,515,641	14,554,423	15,355,542	53,799,963
12	Franchise Fees	408.1	4081011: TaxOthThanIncTax-FranFeeOthCit	30,070,771	30,500,397	31,484,054	32,560,640	-
13	Foreign Insurance Excise Tax	408.1	4081012: TaxOthThanIncTx-ForInsrExcisTx	12,953	-	-	-	-
14	Misc. Tax & Lic Fees - Oregon	408.1	4081013: TaxOthThanIncTx-MiscTax&Lic-OR	2,408,186	2,407,834	2,076,210	2,542,329	2,542,329
15	Misc. Tax & Lic Fees - Montana	408.1	4081014: TaxOthThanIncTx-MiscTax&Lic-MT	379,945	443,904	444,751	392,400	392,400
				127,153,711	132,391,274	136,428,718	147,805,862	157,051,163

PGE
UE 394
Exhibit 207
Rate Base
Scaled (Thousands)

Line No.	Line	Based on Ending Balances
1	Plant in Service	11,630,140
2	Less: Accumulated Depreciation/Amortizatio	(5,284,044)
3	Accumulated Deferred Taxes	(681,954)
4	Accumulated Deferred ITC	
5		
6	**Net Utility Plant**	5,664,142
7		
8	**Operating Materials and Fuel Stocks**	67,724
9		
10	**Deferred Debits**	
11	Glass Insulators	5,477
12	Dispatchable Standby Generation	7,069
13	Wheatridge O&M Start-up Costs	1,517
14		
15	**Deferred Credits**	
16	Injuries & Damages	(8,813)
17	Customer Deposits	(11,737)
18	Incentive Adjustment (UE 283)	(6,333)
19	Major Maintenance Accruals	(7,769)
20	Post Retirement Liabilities	(46,213)
21	Misc. Other	(790)
22		
23		
24	**Working Capital**	73,210
25		
26	**Rate Base**	5,737,484

PGE
UE 394
Exhibit 208
Rate Base Comparison
Scaled (Thousands)

Line No.	Line	UE 335 Approved Order No. 18-464	2022 at GRC Rates	2022 Variance to Approved
1	Plant in Service	10,145,497	11,630,140	1,484,642
2	Less: Accumulated Depreciation/Amortizatio	(4,781,174)	(5,284,044)	(502,871)
3	Accumulated Deferred Taxes	(685,811)	(681,954)	3,857
4	Accumulated Deferred ITC			
5				
6	**Net Utility Plant**	4,678,513	5,664,142	985,629
7				
8	**Operating Materials and Fuel Stocks**	78,945	67,724	(11,221)
9				
10	**Deferred Debits**			
11	Glass Insulators	5,473	5,477	4
12	Dispatchable Standby Generation	11,818	7,069	(4,749)
13	Wheatridge O&M Start-up Costs	-	1,517	1,517
14				
15	**Deferred Credits**			
16	Injuries & Damages	(9,075)	(8,813)	262
17	Customer Deposits	(12,580)	(11,737)	843
18	Incentive Adjustment (UE 283)	(8,000)	(6,333)	1,667
19	Major Maintenance Accruals	(7,997)	(7,769)	228
20	Post Retirement Liabilities	(44,889)	(46,213)	(1,324)
21	Misc. Other	(5,299)	(790)	4,509
22				
23				
24	**Working Capital**	57,801	73,210	15,410
25				
26	**Rate Base**	4,744,710	5,737,484	992,774

PGE
UE 394
Exhibit 209
Production Tax Credits (PTCs) in Net Variable Power Cost
Not Scaled

Line No.	Line	System
1		
2	**Production Tax Credits (PTCs) in 2022 Net Variable Power Cost**	
3		
4	Grossed Up for Taxes	(39,084,307)
5	Gross-Up Factor	1.36964
6	PTCs	(28,536,125)

PGE
UE 394
Exhibit 210
2022 Unbundled Results of Operations Summary
Scaled (Thousands)

Line No.	Line	Production Energy	Production Reliability	Transmission	Distribution	Ancillary	Billing	Metering	Consumer	Total
1	Operating Revenues									
2	Sales to Consumers (Rev. Req.)	700,869	416,896	87,205	723,480	5,119	37,795	6,216	127,424	2,105,003
3	Sales for Resale									
4	Other Revenue Detail	1,563	(4,927)	18,644	19,185	(5,119)				29,346
5	Total Operating Revenues	702,431	411,969	105,849	742,665	-	37,795	6,216	127,424	2,134,349
6										
7	Operation & Maintenance									
8	Net Variable Power Cost	363,256	148,510							511,766
9	Total Fixed O&M	66,932	61,681	17,576	152,522					298,711
10	Other O&M	26,909	26,257	7,630	94,036		28,320	3,518	90,144	276,815
11	Total Operating & Maintenance	457,097	236,447	25,206	246,558	-	28,320	3,518	90,144	1,087,292
12										
13	Depreciation & Amortization	96,261	69,423	23,366	184,878		3,345	924	20,258	398,454
14	Other Taxes / Franchise Fees	24,720	17,858	8,834	98,794		1,310	394	5,141	157,051
15	Utility Income Tax	21,738	16,222	9,226	42,740		940	251	2,396	93,513
16										
17	Total Oper. Expenses & Taxes	599,816	339,949	66,633	572,970	-	33,915	5,087	117,940	1,736,311
18										
19	Utility Operating Income	102,615	72,019	39,216	169,694	-	3,880	1,129	9,484	398,038
20										
21	Rate of Return	6.94%	6.94%	6.94%	6.94%		6.94%	6.94%	6.94%	6.94%
22										
23	Return on Equity	9.50%	9.50%	9.50%	9.50%		9.50%	9.50%	9.50%	9.50%
24										
25										

PGE
UE 394
Exhibit 210
2022 Unbundled Results of Operations Summary
Scaled (Thousands)

Line No.	Line	Production Energy	Production Reliability	Transmission	Distribution	Ancillary	Billing	Metering	Consumer	Total
26	**Rate Base**									
27	Gross Plant	2,897,609	2,140,872	994,664	5,170,569		96,432	59,886	270,107	11,630,140
28	Accum. Deprec. / Amort	(1,184,111)	(957,935)	(374,801)	(2,569,840)		(36,688)	(40,918)	(119,751)	(5,284,044)
29	Accum. Def Tax	(286,718)	(164,186)	(61,759)	(155,064)		(3,547)	(2,341)	(8,338)	(681,954)
30										
31										
32	Net Utility Plant	1,426,780	1,018,751	558,104	2,445,665	-	56,197	16,627	142,019	5,664,142
33										
34	Operating Materials & Fuel	37,048	8,715	1,452	20,509					67,724
35	Misc. Deferred Debits	(2,680)	3,497	5,477						6,294
36	Misc. Deferred Credits	(7,298)	(7,180)	(2,568)	(44,287)		(1,698)	(571)	(10,285)	(73,887)
37	Working Cash	25,291	14,334	2,810	24,159		1,430	215	4,973	73,210
38										
39	Total Rate Base	1,479,142	1,038,116	565,275	2,446,046	-	55,928	16,271	136,707	5,737,484
40										
41	*Weighted Cost of Debt*	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%
42	*Equity Share of Cap Structure*	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Anne Mersereau
Tamara Neitzke

July 9, 2021

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 & Inclusion. 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, and health 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.

Our qualifications are included 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. In particular, we describe how PGE's compensation philosophy is designed to address compensation challenges, and we present total compensation costs for the 2022 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 2022?

A. PGE forecasts approximately $470.5 million in total compensation costs for 2022. Table 1 below summarizes the cost and compensation components of the 2020 actuals and 2022 test year.

Table 1
Estimated Total Compensation Costs ($Millions)

Component	**2020 Actuals**	**2022 Test Year**	**2020-2022 Delta**
Total Labor	$362.5	$351.7	($10.8)
Incentives	$29.1	$18.6	($10.6)
Benefits	$99.3	$103.6	$4.3
Total Compensation*	**$491.0**	**$473.9**	**($17.1)**

** Numbers may not sum due to rounding.*

The net difference between 2020 actuals and forecast 2022 test year costs is a decrease of $17.1 million. Looking at the component parts, total aggregate labor costs decrease by $10.8 million, or 1.5% annually, due to a 40% annual decrease in contract labor and a 16% annual decrease to overtime, which is partially offset by increases from wage escalation and PGE straight-time labor requirements. We further explain the changes in more detail in Section III below.

A primary driver of benefits costs from 2020 to 2022 is an increase in health and wellness costs ($5.8 million) and post retirement costs ($3.0 million). The increases to benefits are more than fully offset by the decrease in PGE's total labor costs, as described above, and PGE's incentive request, which represents a reduction of approximately $10.6 million from 2020 actuals. See PGE Exhibit 301 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, affordable, cleaner, and more secure energy to our customers. PGE's culture has evolved to one this is customer focused and results driven. To keep costs reasonable for customers, PGE actively controls costs by targeting market median conditions for our compensation program. Our ability to serve our customers and their needs is highly dependent on our ability to attract and retain a skilled workforce. Remarkably, while, as of April 2021, there is still an unemployment rate of approximately 6% in Oregon, the utilities industry only represents a fractional share of the new unemployment claims for 2020 and 2021.[1] Thus, while a segment of the population remain persistently unemployed, recruiting and retaining the highly skilled employees needed to effectively and efficiently support PGE's operations continues to remain challenging. We discuss this and other challenges in more detail below.

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.

[1] Oregon initial claims for unemployment insurance filed by workers in the utilities industry comprise just 0.11% of the total claims filed from January 1, 2020 through May 29, 2021

- Incentive Pay: PGE designs its incentive pay 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.[2] PGE strives to maintain a benefits package that supports our employees' wellbeing and balances the features and costs both among employee groups and against what other employers in our market 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:

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; and
4. Managing and controlling our benefit costs while providing benefit packages that attract and retain well-qualified, skilled employees that PGE needs.

[2] PGE's pension plan is closed to all new employees. Effective February 1, 2009, new non-bargaining employees were ineligible for the pension plan. Effective January 1, 2012, new bargaining unit employees at Coyote Springs 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.

A. Talent Acquisition

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 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 higher 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.[3] 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 abilities along with technical abilities, leading PGE to compete for such managerial 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.

[3] Including advanced technical, mathematical, and mechanical concepts.

Our recruiting challenges for these necessary skills continue to be most acute for several specialties.[4] We have described some similar recruiting challenges in our past rate case filings, and even with the unemployment rate at a higher level than in years past, the regional and national demand for highly skilled workers remains high,[5] allowing these workers to be selective about changing jobs or moving. In particular, for positions such as line workers,[6] we find that we must more frequently recruit individuals who require relocation.

There are also more recent workplace developments that are placing new and additional strains on PGE's recruitment and retention efforts. 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 in remote work along with a number of other factors, labor department data indicates that turnover at a national level is at its highest level in two decades.[7] In short, it is getting harder for companies to retain their existing talent.

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

A. We approach this challenge in four ways:

---

[4] 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.

[5] 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.

[6] Tradesperson who constructs and maintains electric transmission and distribution lines.

[7] Forget Going Back to the Office—People Are Just Quitting Instead - WSJ - https://www.wsj.com/articles/forget-going-back-to-the-officepeople-are-just-quitting-instead-11623576602?st=bo0axn75cn7rgyz&reflink=article_email_share

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. We also often find it necessary 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.

In addition, PGE uses an employee referral program to increase the number of qualified applicants for select PGE positions. This program provides incentives to current PGE employees for referring qualified external candidates for specific in-demand positions.[8]

[8] Examples of select PGE positions include journeyman lineman (line worker), supervisory control and data acquisition (SCADA) engineers, and IT professionals.

B. Development

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

A. Ultimately, our challenge of recruiting 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). This is important because a significant portion of our work force is likely to retire or otherwise leave PGE within the next three to five years. From 2015 to 2020, the percentage of non-represented PGE employees with over five years of service to the company has dropped from approximately 73% of PGE's workforce to just over 50%. Additionally, PGE continues to have approximately one-quarter of the workforce retirement eligible. PGE's current expected annual turnover rate is approximately 10%, which equates to about 280 vacancies from turnover every year. Of this, approximately 100 annual retirements are projected per year, through 2025, with retirements at the senior manager and executive level increasing the need for succession planning. 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 where it is cost-effective. In addition to these programs, PGE uses the following work force planning strategies:

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

- 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, and this is borne out by research studies, that employee diversity and inclusion has multiple business benefits, including higher levels of employee engagement, more effective customer engagement, and improved employee and safety performance. The safety benefits come from employees' feeling a greater sense of inclusion, which encourages them to take more ownership for acting in a safe manner and to speak up when they see something unsafe.

PGE's service area grows more diverse each year, and while our workforce diversity has improved, we continue to face challenges in attracting well-qualified and skilled employees who match the demographics of our communities, particularly in senior-level management and the trades.[9] In our efforts to attract a diverse workforce, we experience heightened

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

competition because 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. In 2020 and 2021, these examples include:

- Identification of five commitment areas and corresponding actions to move PGE forward in our journey toward racial equity through hosting nine all company Racial Equity Listening Sessions with over 130 employee participants, in addition to over 30 officer-led sessions with over 400 employee participants;
- Hosting unconscious bias training for employees, learning tools and techniques to create a more inclusive workplace culture;
- Launch of leadership development programs for high potential women and Black, Indigenous, and people of color;
- Earning the Best Place to Work for LGBTQ[10] Equality by the Human Rights Campaign Foundation for the seventh consecutive year; and
- Inclusion in the Bloomberg Gender-Equality Index for the second consecutive year.

PGE is also working to build a more diverse talent pipeline through developing relationships with educational, workforce, and industry stakeholders. For example, PGE has

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

collaborated with the Emerging Leaders Internship (ELI) program to expand the diversity pool of our summer hire program, and we are placing a greater emphasis and focus on diversity with the Multiple Engineering Cooperative Program, the Civil Engineering Cooperative Program, and our Pre-Apprentice Program. Internships are one entry point to PGE and by focusing on the diversity of this and similar entry-points, PGE is better able to develop a workforce that is representative of the communities we serve. We found internships to be successful in 2020 and we plan to increase our efforts in targeting positions for internships with ELI in 2021 and 2022. We're 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. While we are seeing a more moderate increase to health care costs as compared to recent history,[11] on average, health care costs continue to rise faster than overall wages.

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 for both PGE and employees, positioning PGE to attract employees in a cost-effective manner for customers. This shift in focus includes the movement of all non-bargaining employees into

[11] This is at least in part attributable to the impacts of COVID-19 in 2020.

Health Savings Account based health plans and the adoption of a company-wide wellness platform that engages and incentivizes healthy behaviors. We discuss these and other changes in more detail in Section V below.

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, and responsibly generated energy to customers. This includes both regular and temporary PGE employees, along with contract employees.

Q. Please explain how PGE has adjusted its classification of labor costs since the last general rate case.

A. To provide a more accurate reflection of our total labor and to better align with how labor is viewed, planned for, and controlled internally, we define total labor as both PGE labor <u>and</u> contract labor. Taking this view helps ensure the right talent, in the right roles at the right time.

Q. Are any of these cost categories new to PGE?

A. No. Fundamentally, nothing in PGE's cost structure has changed. These categories of costs (as defined by "cost element" within PGE's accounting system) are generally the same as they were in our last general rate case. We are only modifying how we classify labor versus non-labor costs, within a general rate case, to provide a more consistent and accurate analysis of PGE's true historical and forecasted labor requirements. In short, we have now moved non-PGE (i.e., contract) labor into the labor classification.

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, 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 account 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 along with on-going base-business requirements. Total labor dollars provide a better 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 highly 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 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.

Looking at FTEs tends to mask overall changes to PGE's labor needs, as neither contractor hours nor overtime hours is 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. Additionally, as illustrated above, it is possible to have either more FTEs at a lower cost or less 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, 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 this change in focus also involve changes to the inputs used 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 non-bargaining PGE employees.

B. Market-Based Pay Structure

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

A. PGE periodically 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 these data to determine the midpoint for each compensation grade within the pay structure. Pay ranges are then established around the midpoint as a means 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 Oregon Pay Equity Act.

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

A. Due to the effects of the economic downturn, overall wages and salaries escalation both in Oregon and nationally softened slightly in 2020, compared to recent historical periods, with the 2020 full year nominal percent change in Oregon wages in salaries increasing only 1.6%. However, according to the State of Oregon Office of Economic Analysis (OEA):

> "the labor market is expected to remain tight for the foreseeable future in large part due to demographics and the large number of Baby Boomers retiring. Labor will remain a challenge for firms. But a tight labor market also works wonders for employees with strong wage gains and more plentiful job opportunities."[12]

In support of their expectation the May 2021 quarterly OEA report forecasts Oregon's nominal wages and salaries to increase by 8.8% and 5.6% for 2021 and 2022, respectively. 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 2020, we compared our hourly nonunion and salaried non-officer positions with the market. As a result, we adjusted the midpoints of our pay structures to align with market,

[12] OEA May 2021 Economic and Revenue Forecast, Page 3. https://www.oregon.gov/das/OEA/Documents/forecast0521.pdf

which increased by an overall average of 0.9%. However, as evidenced above, we expect the 2021 results to be much more pronounced. The details of the 2020 study are provided in our confidential work papers.

Q. What is PGE's 2022 test year forecast for total labor?

A. Tables 2 and 3 below summarize PGE total labor costs for 2020 and 2022 by division and by cost category respectively. Additional detail can be found in PGE Exhibit 302.

Table 2
Total Labor Costs by Division ($000)

	2020 Actuals (3)	**2022 Test Year (1)**
Administrative and General	$88,843	$86,929
Customer Accounts	$22,788	$24,115
Customer Service	$12,044	$13,429
Generation	$57,253	$49,687
Transmission & Distribution	$181,577	$177,531
Total Wages & Salaries (2)	**$362,506**	**$351,692**

(1)2021 & 2022 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 3
Total Labor Costs by Cost Category ($000)

	2020 Actuals (3)	**2022 Test Year (1)**
Salaried Straight Time	$169,109	$181,420
Union Straight Time	$60,004	$63,387
Hourly Straight Time	$19,539	$22,116
Union Overtime	$26,516	$18,032
Hourly Overtime	$804	$1,286
Temporary PGE Labor	$1,944	$2,799
Contract Labor	$41,907	$15,050
Paid Time Off (PTO)	$42,682	$47,603
Total Wages & Salaries (2)	**$362,506**	**$351,692**

(1) 2021 & 2022 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.

We have worked hard to drive efficiencies across our business in our labor force, which is illustrated above with overall wages and salaries for 2022 below that of the 2020 base year. Details of our efforts are discussed in separate testimonies. While substantially lower than current Oregon economic predictions, in an effort to mitigate the overall impact of this general rate case request and reduce the overall increase to customer prices, PGE used a rate of just 2.5% to escalate its non-bargaining wages and salaries for 2021 and 3.0% to escalate non-bargaining wages and salaries for 2022. For union wages and salaries, PGE applied a rate of 3.5% for 2021 and 2022, which is based on our expectations regarding the upcoming collective bargaining process.

Q. Please identify the bargaining unit contracts in effect with the IBEW Local No. 125 (IBEW).

A. There are two collective bargaining agreements, one for each bargaining unit. The largest bargaining unit (i.e., the majority of PGE's union employees, referred to here as "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 CBAs in 2021 or 2022?

A. Yes. We expect to begin negotiations this year, which will likely impact the overall structure for both CBAs. Most significantly, will be an attempt to bargain an agreement that covers employees at Coyote, Port Westward, and Carty, as well as cover represented employees at all PGE generating facilities. As a result, this new CBA will likely contain bargained for wage escalation and benefits offerings similar to that contained in the current BU1 CBA. As such, we have developed our 2022 test year labor and benefits forecast using this assumption.

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,[13] 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 schedules). Thus, the bargaining agreements in their entirety reflect the negotiated outcomes that both parties' support.

Q. Has PGE made any adjustments to its total labor costs for 2022?

A. Yes. To account for vacancies and/or unfilled positions, PGE has included a $10 million O&M reduction to its base budget wages and salaries forecast. This amount is reflected in the above tables.

[13] In an arm's length negotiation, each party is acting independently, and in their own self-interest.

IV. Incentives

Q. What is incentive pay?

A. Incentive pay is part of a competitive total compensation package where high performing employees are rewarded with a larger total annual compensation package based on pre-established 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 of the "at risk" component 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 towards our long-term strategic goals and our commitment to core principles, 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 50th 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. 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. Additionally, PGE has just recently introduced goals to support its diversity initiatives.

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

A. Incentive pay is approximately 9.5% of PGE's 2022 total compensation costs. However, because PGE has made a pre-filing adjustment to our incentives request for this filing, the amount of incentive pay in our request represents approximately 3.9% of PGE's 2022 total compensation. Our pre-filing adjustment removes 100% of all Officer incentives and 50% of the cost of all other incentive plans. Table 4 below summarizes PGE's actual incentive costs for 2020 and our request for 2022. We discuss the four categories of incentive plans in subsections A through C below.

Table 4
Total Incentives ($000)

Incentive Plans	**2020 Actuals**	**2022 Test Year[1]**
Performance Incentive Compensation	$8,567	$9,842
Annual Cash Incentive	$9,547	$5,141
Stock (long-term incentive plan)	$10,887	$3,437
One-time recognition and Miscellaneous	$133	$146
Total Incentives[2]	$29,133	$18,566

(1) *Amounts are net of PGE's pre-filing adjustments.*
(2) *Numbers may not sum due to rounding.*

Q. Why did PGE make these adjustments?

A. We made these adjustments to help mitigate the overall size of the rate increase. PGE has worked diligently to design incentive plans that provide reasonable incentive to attract and retain qualified individuals, to achieve corporate goals, and to benefit customers. This helps minimize turnover, increase efficiency, and produces positive financial results; all goals that directly and positively impact PGE's costs and value to customers. Although we have made these incentive reductions in this filing, we still believe that all of our incentive costs are prudent and appropriate.

A. Performance Incentive Compensation

Q. What is the Performance Incentive Compensation (PIC) Plan?

A. The PIC Plan is PGE's broad-based incentive program for most non-bargaining employees. The PIC plan rewards eligible employees with cash payments for performance tied to results that support PGE's Corporate Imperatives[14] and lead to greater value for customers and stakeholders.

Q. Please explain how the PIC plan creates benefits for customers.

A. PGE's PIC plan creates customer benefit by basing the incentive pool on two goals that provide value to customers:

- Individual or Team Performance Goals: These performance goals are designed to stretch performance and promote individual growth and development, while achieving corporate operational goals (e.g., efficiency, meeting or improving operational standards). Strong individual performance is critical in achieving

[14] PGE's three long-term Corporate Imperatives are to: 1) Decarbonize, 2) Electrify, and 3) Perform.

strong company performance, which in turn, leads to greater value for PGE's customers.

- Financial Performance: While financial performance represents a smaller percentage of PGE's payout ratio compared to individual and team performance, it is still important, as financial strength can reduce customer rates through lower borrowing costs and, thus, a lower cost of capital.

Actual award amounts are based on employees' incentive targets and their performance relative to these goals.

B. Annual Cash Incentive

Q. What is the Annual Cash Incentive (ACI) Plan?

A. PGE's ACI Plan is an incentive plan for executives and key non-bargaining employees whose contributions have a strategic and measurable impact on the success of PGE's goals and performance results.

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 described below that deliver value to customers:

- 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) Decarbonization, customers want affordable, reliable energy - and they want their choices to be cleaner than ever before; 2) Electrification, help meet customer and stakeholder goals of driving decarbonization of the entire economy, through beneficial electrification of end uses like transportation; and 3) Performance, delivery of affordable, reliable, and cleaner energy choices equitably to all customers, through positive interactions and exceptional customer experiences.

- 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).
- Electric Service Power Quality and 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), the average number of interruptions that a customer would experience; and 2) Customer Average Interruption Duration Index, the average time, once the outage occurs, to restore service to the customer.
- Generation Availability: This goal measures the amount of time that our generating plants are available to produce energy. Plant availability positively influences power costs by ensuring that the lowest cost resources are available for dispatch.[15]
- Financial Performance: This goal measures actual earnings per share (EPS) relative to an EPS 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.

[15] PGE Confidential Exhibit 702 provides plant availability statistics.

C. Other 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.[16] The Public Utility Commission of Oregon (OPUC or 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."[17]

PGE's 2022 forecast for its long-term stock incentive program is $12.1 million, but our request is approximately $3.4 million for the 2022 total long-term incentive expense. Our request reflects the removal of the Officer Long-term Incentive Program costs and a 50% reduction for 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 2022 forecast for one-time recognition awards is approximately $0.3 million, but our request is approximately $0.15 million, reflecting a 50% reduction.

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[16] A portion of the long-term incentive program is now paid out annually in the form of restricted stock units.
[17] OPUC 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 2022 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. 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: 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 5 below, we project 2022 employee benefit costs of approximately $103.6 million. PGE's total benefit costs are expected to see a relatively small increase of $4.3 million from 2020 to 2022, due primarily to increases in medical and dental costs and retirement savings plan costs.

Table 5
Total Benefits ($000)

Benefits Compensation Component	2020 Actuals	2022 Test Year
Health and Wellness	$47,805	$53,646
Disability and Life Insurance	$4,100	$4,571
Post-Retirement	$39,957	$42,985
Miscellaneous Benefits	$6,684	$1,632
Benefits Administration	$787	$786
Total Benefits*	$99,332	$103,620

** Numbers may not sum due to rounding.*

Q. Previously you discussed the expected negotiations of the collective bargaining agreement for union employees. Does PGE expect there to be any material changes to benefits in the terms of the CBA?

A. Yes. As we mentioned in Section III, we expect there to be a change in the structure of PGE's two bargaining units, which will likely change some of the benefits offered to current BU2 employees. More specifically, while the future structure of PGE's bargaining units is to some extent still unknown, we expect 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 utilities with similar revenues. BENVAL provides a complete competitive analysis of the value of a benefit 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. The tools a company can use to affect medical costs are extremely diverse; BENVAL gathers all the relevant information related to a company's health care and other benefits plan offerings in order to accurately benchmark them against other peer groups. BENVAL is a leading benefits benchmark study 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 12 regulated utilities with annual revenue ranging from $1 billion to $3 billion. These peer utilities derive the majority of their revenue from the electric business. The peer group includes utilities across the U.S., with a balanced representation across the western and eastern regions.

Q. Where does BENVAL place PGE in its medical and other benefit costs?

A. According to the 2019 BENVAL study, PGE's employer-paid non-bargaining medical costs were approximately 12% higher, and a key driver leading to PGE's entire benefit program being approximately 5% higher than the average of its peers.[18]

Q. How has PGE responded to the 2019 results?

A. While PGE's employer paid costs were higher than the peer group average, <u>total</u> medical costs (employer plus employee costs) came in lower than the peer group average. As a result of this, and in order to move PGE's employer paid costs into greater alignment with the peer group average, PGE increased the cost sharing for employee paid medical costs. As a result, employees now pay a greater share of their total medical costs.[19] Since the BENVAL study is a biennial survey, PGE will be participating in this survey during 2021 and we expect to see the results of this change compared to our peer group average sometime towards the beginning of Q3, 2021.

[18] These survey results are provided as confidential PGE Exhibit 303C.
[19] Approximately 8% more on average, as compared to 2019 employee share costs.

Q. Please explain why Health and Wellness costs are forecasted to increase approximately $5.8 million from 2020 to 2022.

A. PGE's increase to Health and Wellness of $5.8 million, or approximately 5.9% annually is driven by several factors:

- First, while PGE's direct labor requirements are relatively flat compared to 2019, due to the nation-wide pandemic, PGE experienced unsustainable delays in the back filling of certain open positions for 2020. The result of this action is a decrease in PGE's 2020 regular employees and thus a decrease to 2020 Health and Wellness costs, as compared to 2019 actuals and 2021 and 2022 forecasts. When comparing PGE's 2022 Health and Wellness forecast to 2019 actuals, the average annual increase is only 1.6%.
- Second, though lower than in the recent past, PGE has seen increases in medical and dental rates from benefit providers for 2021 and expects similar increases for 2022. PGE's benefits consultant, Mercer, provides PGE's forecasted rate increases for the 2022 forecast. Mercer uses national and regional trending data paired with PGE's employee demographics and usage trends in order to calculate a customized forecasted rate increase.
- Finally, because of the shift in assumptions for PGE's Bargaining Unit employees as described above and in Section III, PGE expects a larger increase to union medical costs. Health care plan offerings and cost sharing for the bargaining unit are a negotiated benefit and managed by a Taft-Hartley Trust, which results in less flexibility for PGE to enact broad design changes. Currently, this results in union medical and dental costs, that while in line with industry standards, are higher per

employee than PGE's non-union medical and dental. Thus, due to the likelihood of PGE's BU2 employees being incorporated into the BU1 union medical plan, the annual average increase forecast for union health and dental is approximately 6.3%, compared to a 4.7% annual average increase for PGE's non-union health and dental costs.

Q. What strategies is PGE employing to help slow the increase of its health care costs?

A. PGE has employed some strategies to help lower the costs of health care, which has consistently outpaced the rate of inflation.[20] 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. We use various tools to execute on this strategy. Most recently, PGE chose to stop offering retiree medical plans, as we found that our usage of this plan was low and that comparable plans for retirees existed in the marketplace at a similar or lessor cost. For current employees, the largest tool PGE currently has at its disposal to help control future health care costs for both the company and employees is the transition from traditional medical plans to Health Savings Account-qualified (i.e., HSA-qualified) medical plans.

As of 2018, PGE began offering only HSA-qualified plans to non-bargaining employees and is offering the option to union employees. The HSA-qualified medical plan design encourages wise use of health care services, because employees are responsible for 100% of service costs up to the medical plan's deductible, except for preventive care which is covered.

[20] According to the Kaiser Family Foundation: "In 2020, the average annual premiums for employer-sponsored health insurance are $7,470 for single coverage and $21,342 for family coverage. The average single premium increased 4% and the average family premium increased 4% over the past year. Workers' wages increased 3.4% and inflation increased 2.1%." See https://www.kff.org/report-section/ehbs-2020-summary-of-findings/#:~:text=In%202020%2C%20the%20average%20annual,%25%20and%20inflation%20increased%202.1%25.

In conjunction with the shift to HSA-qualified medical plans, another tool PGE has increased its focus on is promoting overall employee wellness.

Finally, as discussed above, PGE continually benchmarks and, if warranted, adjusts the cost sharing ratio of non-union medical plan offerings in order to remain in alignment with industry benchmarks.

Q. Why does PGE include wellness programs as one of its total benefits components?

A. PGE offers wellness programs to provide early detection of risk factors, intervention and management of health issues. 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 able to be 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.[21] 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 2022.

A. PGE's disability and life insurance benefits are comprised of union short-term disability (STD) insurance, long-term disability insurance, and retiree group life insurance for all employees.

PGE forecasts STD insurance costs of approximately $0.7 million in 2022. This represents a less than $0.1 million increase from 2020 and is the result of PGE's current

[21] 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 healthcare claims costs compared to non-members.

assumption that BU2 employees will be moving into the plan, coupled with a 5% rate increase from the provider.

PGE forecasts long-term disability (LTD) benefits for union and non-union employees to be approximately $2.2 million in 2022.[22] PGE uses forecasts from both Willis Towers Watson, a third-party actuary, and Mercer 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 actually paid by PGE in that year.

PGE forecasts retiree group life insurance costs to be approximately $1.6 million in 2022. 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.[23]

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

[22] This includes approximately $0.6 million in LTD medical costs and $1.7 million in LTD income benefit projections.
[23] To comply with ERISA accounting guidelines, PGE classifies the HRA as a health and wellness benefit, even though employees do not receive the benefit until after retiring from PGE.

total compensation package to attract well-qualified, skilled employees in the current competitive marketplace.

Q. What is PGE's 401(k) forecast for 2022?

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 2020 to 2022, costs associated with the 401(k) are expected to increase from $25.8 million to $28.7 million. This is primarily due to a shift in employee demographics. As PGE continues to experience employee turnover, a larger percentage of employees are not part of PGE's legacy pension plan. 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 employees in the pension plan and a larger share of employees qualifying for the employer contribution to their 401(k) plan.

Q. What is PGE's HRA forecast for 2022?

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. PGE previously provided this benefit for non-bargaining employees as well but stopped contributions to current participants and closed the plan to new participants in 2018. Union HRA costs relate to the accumulation of notional hours for current employees and retirees receiving current HRA benefits. Total HRA costs for 2022 are expected to be approximately $2.3 million.

Q. What is PGE's pension cost forecast for 2022?

A. PGE's 2022 pension cost is forecasted to be $19.6 million (or approximately $11.9 million after capitalization), which is slightly below 2020 actuals.

Q. Is PGE requesting any changes to its treatment of pension expense in this proceeding?

A. No. PGE continues to capitalize pension and post-retirement plans in a manner consistent with PGE's method prior to the issuance of FASB ASU 2020-07, per the stipulated agreement in UE 319, PGE's 2018 test year general rate case.

Q. How is pension expense calculated?

A. Pension expense, more commonly known as "FAS 87 net periodic benefit cost,"[24] 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 2022 pension expense continues to use an expected long-term rate of return of 7.0%, which is consistent with the rate used in our last general rate case and based on the pension plan's asset allocation.

Q. What assumption does PGE use for its discount rate?

A. PGE uses a discount rate of 2.53%, 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?

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[24] 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."

A. Discount rates have continued to decline in recent years, with the above forecasted discount rate for 2022 pension expense at a historic low.

Q. Please discuss the current state of PGE's pension plan.

A. Overall, the funded status of PGE's pension plan continues to hover around 70%. With discount rates remaining at a historically low level, the nominal growth of PGE's pension liabilities continues to outpace the growth of pension plan assets, even with higher than average growth in 2019 and 2020. In other words, while PGE has experienced above average plan returns, they are still not enough to cover the growth of future expected liabilities.

Q. Has this resulted in cash contributions into the plan?

A. Yes. In order to address and maintain the funded status of the plan, which dropped due to negative returns in 2018, and due to the historically low discount rate environment, PGE contributed approximately $9 million into the plan during 2018 and $62 million for 2019. While these cash contributions did not significantly increase the funded status of our pension plan, they helped to offset actuarial losses for 2018 and maintain PGE's current funded status in the near term. PGE continues to actively review its liability management strategies for available options to prudently increase our funded status, reduce plan risk, and reduce our overall plan expense.

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 $1.6 million in 2022. 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 2022 cost for benefits administration?

A. PGE forecasts 2022 benefits administration costs to be approximately $0.8 million, which is consistent with 2020 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 nearly thirty years and includes various roles at PGE for the last eleven 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 T&D 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 Gov. 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.

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. I joined 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

Exhibit	**Description**
301	PGE Total Compensation Costs – 2018 Actuals to 2022 Test Year
302	PGE Total Labor Costs – 2018 Actuals to 2022 Test Year
303C	2020 BENVAL Ranking – Entire Benefit Program

Total Compensation WP	a-Dec - 2018	a-Dec - 2019	a-Dec - 2020	Dec - 2021	2022 TY Request	Base Year-Test Year Delta	Base Year-Test Year Annual %
BENEFITS							
Benefits Administration							
Subtotal Benefits Administration	**481,868**	**565,810**	**787,059**	**764,336**	**786,168**	**(890)**	**(0.1%)**
Education Plan							
Subtotal Education Plan	**231,249**	**150,497**	**120,238**	**459,996**	**459,996**	**339,758**	**95.6%**
Employee Assistance Program							
Subtotal Employee Assistance Program	**69,604**	**55,819**	**93,890**	**85,320**	**85,320**	**(8,570)**	**(4.7%)**
Employee Wellness Program							
Subtotal Employee Wellness Program	**368,404**	**198,980**	**91,039**	**241,701**	**244,399**	**153,359**	**63.8%**
Group Life Insurance							
Subtotal Group Life Insurance	**1,058,377**	**1,223,537**	**1,335,046**	**1,600,939**	**1,605,427**	**270,381**	**9.7%**
Health & Dental Plan							
Active Non-Union Health & Dental	32,474,013	35,528,284	33,199,771	34,871,000	36,397,699	3,197,928	4.7%
Active Union Health & Dental	14,045,590	15,309,101	15,327,621	15,444,400	17,322,046	1,994,425	6.3%
Health & Dental Administration	251,968	333,712	317,097	338,449	347,168	30,071	4.6%
Retiree Non-Union Health & Dental	497,034	589,084	(1,207,452)	64,932	72,180	1,279,632	#NUM!
Retiree Union Health & Dental	1,471	5,046	(17,092)	(847,332)	(822,456)	(805,364)	593.7%
Subtotal Health & Dental Plan	**47,270,077**	**51,765,226**	**47,619,945**	**49,871,449**	**53,316,637**	**5,696,692**	**5.8%**
Health Reimbursement Account							
Subtotal Health Reimbursement Account	**3,204,489**	**2,383,002**	**2,024,970**	**2,323,152**	**2,332,272**	**307,302**	**7.3%**
Involuntary Severance Program							
Subtotal Involuntary Severance Program	**2,194,466**	**3,724,058**	**6,830,872**			**(6,830,872)**	**(100.0%)**
Long Term Disability Benefits							
Subtotal Long Term Disability Benefits	**1,016,575**	**1,735,049**	**2,114,003**	**1,894,926**	**2,238,534**	**124,531**	**2.9%**
Misc. Employee Benefits							
Subtotal Misc. Employee Benefits	**461,644**	**974,029**	**(267,544)**	**1,185,897**	**1,171,738**	**1,439,283**	**#NUM!**
Retirement Savings Plan							
Subtotal Retirement Savings Plan	**22,553,807**	**24,859,928**	**25,775,664**	**27,460,473**	**28,741,980**	**2,966,316**	**5.6%**
Short Term Disability Insurance							
Subtotal Short Term Disability Insurance	**657,288**	**680,004**	**651,090**	**664,400**	**726,800**	**75,710**	**5.7%**
Subtotal BENEFITS	**79,567,847**	**88,315,937**	**87,176,273**	**86,552,589**	**91,709,271**	**4,532,999**	**2.6%**
INCENTIVES							
ACI							
Boardman ACI	61,181	(84,513)					#DIV/0!
Officer ACI	2,635,661	2,620,715	1,070,755	2,753,772		(1,070,755)	(100.0%)
Pelton ACI	2,776	11,509	32,785	35,466	13,722	(19,063)	(35.3%)
PGE General Operations ACI	4,832,026	7,910,305	7,920,620	8,432,784	4,579,818	(3,340,802)	(24.0%)
Wholesale Marketing ACI	1,724,986	1,082,994	522,937	1,157,772	548,388	25,451	2.4%
Subtotal ACI	**9,256,629**	**11,541,010**	**9,547,097**	**12,379,794**	**5,141,928**	**(4,405,169)**	**(26.6%)**
Notables & Misc.							
Miscellaneous Awards	3,900	4,465	1,375			(1,375)	(100.0%)
Notable Achievement Awards	813,447	694,222	131,263	291,312	145,656	14,393	5.3%
Subtotal Notables & Misc.	**817,347**	**698,688**	**132,638**	**291,312**	**145,656**	**13,018**	**4.8%**
PIC							
Biglow Canyon PIC	32,534	55,815	18,370	38,460	15,522	(2,848)	(8.1%)
Carty PIC	738,703	658,511	1,579,229	676,596	399,534	(1,179,695)	(49.7%)
Coyote Springs PIC	588,829	425,872	455,906	374,844	208,380	(247,526)	(32.4%)
Pelton PIC	9,223	(21,818)	19,624	15,033	5,815	(13,808)	(45.6%)
PGE General Operations PIC	10,373,274	8,494,500	5,659,505	16,672,968	8,776,272	3,116,767	24.5%
Port Westward PIC	740,700	1,096,999	831,363	757,656	426,960	(404,403)	(28.3%)
Tucannon River PIC	37,245	47,087	2,804	19,032	9,750	6,946	86.5%
Subtotal PIC	**12,520,508**	**10,756,967**	**8,566,799**	**18,554,589**	**9,842,233**	**1,275,434**	**7.2%**
Stock Incentive Plan							
Board of Directors Stock Incentives	924,091	1,268,574	1,185,125	1,090,644	632,502	(552,623)	(26.9%)
Officer Stock Incentives	2,722,540	4,364,815	4,441,960	7,507,920		(4,441,960)	(100.0%)
PGE Stock Incentives	1,446,888	3,502,861	5,259,792	4,864,668	2,803,998	(2,455,794)	(27.0%)
Subtotal Stock Incentive Plan	**5,093,518**	**9,136,250**	**10,886,877**	**13,463,232**	**3,436,500**	**(7,450,377)**	**(43.8%)**
Subtotal INCENTIVES	**27,688,003**	**32,132,914**	**29,133,411**	**44,688,927**	**18,566,317**	**(10,567,094)**	**(20.2%)**
PENSION							
Pension							
Pension	16,318,822	12,680,871	12,156,159	15,056,487	11,911,207	(244,952)	(1.0%)
Subtotal Pension	**16,318,822**	**12,680,871**	**12,156,159**	**15,056,487**	**11,911,207**	**(244,952)**	**(1.0%)**
Subtotal PENSION	**16,318,822**	**12,680,871**	**12,156,159**	**15,056,487**	**11,911,207**	**(244,952)**	**(1.0%)**
Total Aggregate Labor							
O&M Labor	240,381,397	231,021,205	215,114,927	215,036,439	228,996,658	13,881,731	3.2%
Capital Labor	117,646,906	144,237,841	147,391,042	123,665,959	122,695,827	(24,695,215)	(8.8%)
Subtotal Aggregate Labor	**358,028,303**	**375,259,046**	**362,505,969**	**338,702,398**	**351,692,484**	**(10,813,484)**	**(1.5%)**
Total	**481,602,975**	**508,388,769**	**490,971,812**	**485,000,400**	**473,879,280**	**(17,092,532)**	**(1.8%)**

Aggregate Wages by Cost Element	Dec - 2018	Dec - 2019	Dec - 2020	Dec - 2021	Dec - 2022	Base Year-Test Year Delta	Base Year-Test Year Annual %
1101: Straight-Time Labor - Salary	147,940,354	160,259,472	169,517,044	173,388,002	182,369,549	12,852,505	3.7%
1102: Straight-Time Labor - Union	56,183,457	59,567,839	59,727,241	61,574,940	63,225,514	3,498,273	2.9%
1103: Straight-Time Labor - Hourly	20,023,246	20,631,389	19,484,980	21,510,617	22,090,490	2,605,510	6.5%
1200: Other Union Labor				2,708,090	2,802,874	2,802,874	#DIV/0!
1201: Union High Time	68,696	45,392	65,817			(65,817)	(100.0%)
1202: Union Premium Pay	3,516,074	4,152,839	4,395,236			(4,395,236)	(100.0%)
1401: Overtime - Hourly	1,683,500	1,677,810	803,878	1,249,021	1,286,104	482,226	26.5%
1402: Overtime - Union	22,719,496	25,028,943	22,057,622	14,732,887	15,229,314	(6,828,308)	(16.9%)
1501: Temporary Labor Straight Time	6,040,933	3,909,946	1,920,809	2,744,545	2,783,688	862,879	20.4%
1502: Non-PGE Labor Straight Time	57,542,202	53,430,821	35,210,574	13,177,059	12,987,892	(22,222,682)	(39.3%)
1601: Temporary Labor Overtime	242,952	137,688	30,107	26,008	25,765	(4,342)	(7.5%)
1602: Non-PGE Labor Overtime	2,917,356	3,623,782	6,696,303	2,004,200	2,061,822	(4,634,480)	(44.5%)
5104: Vacation Overhead	39,150,038	42,982,718	42,681,702	45,969,637	47,603,121	4,921,419	5.6%
5501: Labor Allocation - ST Salary		(225,287)	(407,915)	(704,868)	(949,554)	(541,639)	52.6%
5502: Labor Allocation-ST Hrly Union		40,007	276,735	276,501	161,388	(115,347)	(23.6%)
5503: Labor Allocation-ST Hrly NonUn		6,445	54,445	53,068	25,625	(28,820)	(31.4%)
5505: Labor Allocation-Union Premium		(149)	(166)			166	(100.0%)
5506: Labor Allocation - Hourly OT		(11)	(10)			10	(100.0%)
5507: Labor Allocation-Union HrlyOT		(5,518)	(2,012)	(261)	(223)	1,789	(66.7%)
5509: Labor Allocation-ST Temporary		(5,081)	(6,422)	(7,047)	(10,887)	(4,465)	30.2%
Total	**358,028,303**	**375,259,046**	**362,505,969**	**338,702,398**	**351,692,484**	**(10,813,484)**	(1.5%)

Aggregate Wages by Division	Dec - 2018	Dec - 2019	Dec - 2020	Dec - 2021	Dec - 2022	Base Year-Test Year Delta	Base Year-Test Year Annual %
A: Customer Accounts	30,397,646	27,536,296	22,788,196	23,402,800	24,115,294	1,327,098	2.87%
B: Customer Service	20,545,434	11,121,515	12,044,485	12,111,392	13,428,887	1,384,402	5.59%
C: A&G	92,144,376	100,981,431	88,843,328	84,031,347	86,929,466	(1,913,863)	(1.08%)
E: T&D	151,925,877	171,967,649	181,577,050	170,423,782	177,531,355	(4,045,695)	(1.12%)
G: Generating - Other	34,349,954	34,302,414	33,025,541	31,292,958	31,697,988	(1,327,552)	(2.03%)
H: Generating - Biglow	819,829	602,486	699,715	654,699	673,030	(26,685)	(1.93%)
I: Generating - Tucannon	519,074	531,049	575,528	698,617	718,221	142,693	11.71%
O: Generating - Boardman	12,869,469	12,643,137	7,826,770			(7,826,770)	(100.00%)
T: Generating - Trojan	1,369,544	1,425,710	1,485,311	1,615,111	1,660,560	175,249	5.73%
V: Generating - Beaver	5,385,394	5,689,140	5,128,517	5,069,679	5,236,727	108,211	1.05%
W: Generating - Port Westward	3,240,569	3,673,152	3,693,574	3,810,342	3,931,342	237,768	3.17%
Y: Generating - Coyote	1,802,103	1,886,449	1,854,765	2,088,765	2,155,871	301,106	7.81%
Z: Generating - Carty	2,659,035	2,898,618	2,963,188	3,502,905	3,613,743	650,555	10.43%
Total	**358,028,303**	**375,259,046**	**362,505,969**	**338,702,398**	**351,692,484**	**(10,813,485)**	(1.5%)

Exhibit 303 contains confidential information and is subject to General Protective Order 21-206.

Information provided in electronic format only.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Corporate Support

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Jim Ajello
Greg Batzler

July 9, 2021

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (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 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 $186.9 million in administrative and general (A&G) costs in 2022 and compare it to 2020 actuals of $193.0 million. We also provide context to show that while a handful of areas are expected to see unavoidable cost increases, these increases are more than fully offset by PGE implementing targeted and ongoing cost cutting measures to help manage our costs and mitigate the economic impact to our customers.

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

A. We classify A&G as the back-office functions that support PGE's direct operations to deliver safe, reliable, affordable, cleaner, and more secure energy to customers, such as 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.[1] PGE Exhibit 401 provides a list of A&G functions plus a summary of costs for 2018 (actuals) through 2022 (test year forecast). Table 1 below summarizes major A&G costs for 2020 actuals and the 2022 test year by functional area.

[1] 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	**2020 Actuals**	**2022 Forecast**	**Delta***
Accounting/Finance	$ 10.3	$ 12.1	$ 1.7
Business Support Services	1.5	1.1	(0.4)
Corp Communications/Public Affairs	3.7	3.1	(0.6)
Corporate Governance	6.8	4.1	(2.7)
Corporate R&D	2.4	2.7	0.3
Environmental Services	2.1	1.8	(0.2)
Facilities/Rent	4.6	6.9	2.3
Governmental Affairs	1.5	1.6	0.0
HR/Employee Support (net of capital allocs.)	10.3	11.2	0.9
Hydro Licensing and Support	0.0	0.0	0.0
Insurance	12.6	17.9	5.4
IT: Direct & Allocated	13.9	16.3	2.5
Legal	7.5	6.9	(0.7)
Performance Management	1.5	1.4	(0.1)
Regulation	2.9	3.4	0.5
Security and Business Continuity	2.4	3.5	1.1
Supply Chain/Contract Services/Purchasing	2.3	1.0	(1.4)
Total for Major Functional Areas*	**$ 86.3**	**$ 94.9**	**$ 8.6**
Benefits (net of capital allocs.)	$ 52.3	$ 59.6	$ 7.2
Corporate Allocations (net)	(4.9)	(1.9)	3.0
Corporate Cost Reductions	0.0	(4.4)	(4.4)
General Plant Maintenance	2.6	2.2	(0.4)
Incentives	29.1	13.7	(15.4)
LC Fees, Revolver Fees, Margin Net Int., & Broker fees	2.1	2.0	(0.1)
Membership Expense	2.5	3.5	1.0
Regulatory Fees	8.3	10.3	2.0
Severance	8.4	0.0	(8.4)
Total Labor Loadings to A&G	0.0	0.0	0.0
Total PTO to A&G	6.3	7.1	0.8
Total Other A&G Costs*	**$ 106.7**	**$ 91.9**	**$ (14.8)**
Total A&G*	**$ 193.0**	**$ 186.9**	**$ (6.1)**

**May not sum due to rounding.*

Q. Is PGE forecasting any increases to A&G cost categories?

A. Yes. While total A&G costs decrease overall when comparing 2020 actuals to the 2022 forecast, there are a handful of functional areas that see cost increases. This is partially attributable to temporary and unsustainable reductions during 2020 in response to COVID-19, coupled with unavoidable cost increases to specific areas that are largely outside of PGE's control (e.g., insurance premiums). In addition to the drivers highlighted above, we will discuss the following:

- Increasing insurance costs, driven by worsening overall market conditions and catastrophic weather conditions, resulting in premiums increasing sharply while available coverage is decreasing;
- Increasing emergency management and security costs, driven by recognition of the potential for detrimental events (e.g., wildfires, storms, etc.) and the need to harden and protect critical energy infrastructure;
- Increasing employee benefits costs, as discussed in PGE Exhibit 300;
- A resumption of normal business activities in accounting and finance, compared to unsustainable cuts in 2020 in response to the COVID-19 pandemic; and
- 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 controlling 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. According to the most recent Bureau of Labor Statistics Consumer Price Index News Release, "(t)he all items index rose 5.0 percent for the 12 months ending May; it has been trending up every month since January." The release continues to state that the index for all items less food and energy has experienced the largest 12-month increase since the period ending June 1992.[2] In fact, for just the three most recently published months of March 2021 through May 2021, the consumer price index for All Urban Consumers has increased by 2%. So, while this rapid upsurge to inflation could result in future impacts to our 2021 and 2022 budgets as we move through the year, PGE is currently continuing to manage its Operations and Maintenance (O&M) costs to a level well below the average rate of inflation.

Q. What is the overall change to A&G costs from 2020 to 2022.

A. As shown in Table 1 above, total A&G costs are forecast to decrease by approximately $6.1 million from 2020 to 2022.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II: Primary A&G Cost Decreases;
- Section III: Primary A&G Cost Increases;
- Section IV: Information Technology;
- Section V: Summary; and
- Section VI: Qualifications.

[2] May 2021 News Release: https://www.bls.gov/news.release/pdf/cpi.pdf

II. Primary A&G Cost Decreases

Q. Why is PGE committing to efficiency savings and cost reductions?

A. PGE recognizes the difficult timing of a general rate case that coincides with the acute financial hardship customers have faced, and many will continue to face, as a result of the COVID-19 pandemic and current unfavorable economic conditions. However, as discussed in PGE Exhibits 100, 200, and 800, the main driver for PGE's rate case timing is capital additions, which are subject to long lead times and which directly benefit customers. Thus, because of this largely unavoidable timing, PGE has made a concerted effort to mitigate our rate increase request and customer price impact, through continued efforts to drive efficiencies across the organization and by implementing targeted and ongoing O&M cost reductions within A&G and other areas of the company.

Q. What efficiency savings has PGE committed to within A&G?

A. To mitigate customer price impacts, PGE has included a total of approximately $10.0 million in targeted and identifiable budget reductions to the 2022 test year request in the following functional areas:

- Supply Chain - $1.5 million reduction
- HR/Employee Support - $0.5 million reduction
- Corporate Governance - $1.8 million reduction
- Directors and Officers (D&O) liability insurance - $0.8 million reduction
- Corporate Cost Reductions - $5.4 million reduction

Q. Please elaborate on the budget reductions applied to supply chain.

A. Although there is a targeted decrease of $1.5 million reflected within the supply chain budget, it ultimately represents overall savings targets that PGE has committed to achieving largely through sourcing and contract renegotiations.

Q. Does PGE know where these savings will be realized?

A. Not yet. Therefore, we have chosen to place the savings target within the supply chain forecast. As actual savings have been realized in 2021 and are realized in 2022, they will be reflected within the functional areas incurring the underlying contract costs.

Q. Please describe how PGE's supply chain function manages costs for customers.

A. As part of normal day-to-day operations, PGE's supply chain function captures both hard and soft cost savings and cost avoidance through competitive solicitations, strategic sourcing initiatives, contract renewal and award negotiations, and make-versus-buy analyses. These savings are then realized in (or, in the case of avoided costs, kept from) various capital and operating areas throughout the company, reflecting PGE's ongoing effort to keep costs low for our customers.

Q. Please elaborate on the budget reductions applied to HR/employee support and to corporate governance.

A. The $0.5 million of budgeted reductions reflected in HR/employee support and $1.8 million of budgeted reductions reflected in the Office of Corporate Finance Officer (CFO) and Treasurer department of PGE's corporate governance area are targeted stretch goals applied to PGE's 2022 forecast in order to mitigate the overall cost increase to customers. While PGE is committed to these savings, it has not yet been determined exactly how these savings will be realized.

Q. Please elaborate on the budget reductions applied to corporate cost reductions.

A. To account for vacancies and/or unfilled positions, PGE has included a $10 million total O&M reduction to its base budget wages and salaries forecast. Of this, $4.4 million is reflected as a reduction to A&G expense.

Q. Has PGE included 100% of meals and entertainment costs in the 2022 test year?

A. No. While we believe these costs are appropriate to request, in an effort to reduce the size of our requested increase and to reflect the Public Utility Commission of Oregon (Commission) Staff's historical treatment of these costs,[3] we are voluntarily reducing the size of our request by approximately 50% of the three-year historical average of our meals and entertainment expenses. This amounts to $1.0 million of the $5.4 million in corporate cost reductions highlighted above. The remaining $4.4 million of corporate cost reductions reflects the A&G portion of PGE's $10.0 million O&M reduction to wages and salaries. Please see PGE Exhibit 300 for more detail regarding this adjustment.

Q. Has PGE made any other voluntary reductions to Corporate Support costs?

A. Yes. While not included in the table above, PGE has chosen to voluntarily remove 100% of all forecasted Officer incentive costs and 50% of all other forecasted incentive compensation costs. While the entirety of PGE's incentive program benefits customers and is a key part of all investor-owned utilities' total compensation, we have made this adjustment to help mitigate the overall size of our rate increase. Please refer to PGE Exhibit 300 for additional discussion regarding PGE's incentive programs.

[3] See page 6 of Exhibit 600 from Staff's opening testimony filed June 6, 2018 in Docket No. UE 335

III. 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 402 and confidential PGE Exhibit 403. In general, the insurance coverage maintained by PGE falls into two broad programs: Property and Casualty. We discuss these below, as well as address retained losses.

Q. What is PGE's forecast for insurance premiums for 2022?

A. As shown in Table 2 below, we expect total Property and Casualty premiums to be approximately $20.3 million. This compares to actual 2020 costs of $13.3 million, an annualized increase of 23.5%. We discuss the primary drivers of these increases in the following sections.

Table 2
Insurance Premiums ($ millions)

Type of Loss	2020 Actuals**	2021 Budget**	2022 Forecast**	Annualized % Increase
Property	$7.2	$9.8	$11.0	24.0%
Casualty	$6.2	$8.8	$9.3***	22.5%
Totals*	**$13.3**	**$18.6**	**$20.3**	**23.5%**

**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 renewable and traditional Property insurance premiums to increase at a 24.0% annualized rate due to an increase in PGE's total insured values coupled with premium rate increases in response to current market conditions. In the Property insurance market, utility insurers have struggled to make an underwriting profit, with underwriters requiring double-digit rate increases while pushing for increased deductibles or reducing their available limits to manage their portfolios.

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

PGE Exhibit 402 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 30.6% in its General Liability insurance program. The adverse wildfire loss activity in California over the last decade is the primary driver of this large premium increase. Additionally, the 2020 Labor Day fires in the Pacific Northwest have further focused underwriters' attention on the catastrophic exposure faced by utilities in the region. The 2020 wildfires will also contribute to further premium increases and/or outright exclusions for wildfires. Other exposures undergoing increased underwriting scrutiny and adversely impacting utility insurance pricing are the perceived risk of large auto fleets, gas pipeline infrastructure, use of drones, hydro facilities and their safety protocols, coal ash ponds, 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 on rates based upon industry-wide losses combined with PGE's own loss history. Cyber Liability rate increases accelerated throughout 2020 with average increases for all accounts up +5%. Aging industrial control systems remain the target of cybercriminals. PGE secured a flat renewal in 2020 with expectations of average annual increases of 5% through 2022. Unforeseen severe casualty losses would produce upward pressure on rates beyond the current forecast. Overall, we anticipate a 23.5% average annualized impact on premiums without taking into effect any unknown increases in premiums due to the natural disaster consequences discussed above between 2020 and 2022.

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 2022 test year?

A. No. In line with our decision to exclude 50% of meals and entertainment costs, we are also excluding 50% of D&O insurance coverage costs to reduce the size of our request for the benefit of our customers.

3. Retained Losses

Q. Please explain retained losses.

A. Retained losses are the portion of any claim falling within PGE's self-insurance retentions for its Auto Liability, General Liability, and Workers' Compensation exposures 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 2020 to 2022?

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 8.3% from 2020 to 2022. In 2021 and 2022, 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	2020 Actuals	2021 Budget	2022 Forecast	Annualized % Increase
Auto & General Liability	$1.5	$2.0	$2.0	14.3%
Workers' Compensation	$1.8	$1.9	$1.9	2.8%
Totals*	**$3.3**	**$3.9**	**$3.9**	**8.3%**

**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. Emergency Management and Security

Q. How much do you expect Business Continuity and Emergency Management (BCEM) and Security costs to increase from 2020 to 2022?

A. As shown in Table 4 below, BCEM costs are forecasted to increase from approximately $0.8 million in 2020 to $1.6 million in 2022. Security costs are expected to increase from approximately $1.5 million to $1.9 million over the same period.

Table 4
BCEM and Security Costs ($ millions)

Functional Area	2020 Actuals	2021 Budget	2022 Forecast	Annualized % Increase
BCEM	$0.8	$1.3	$1.6	39.0%
Security	$1.5	$1.6	$1.9	10.5%
Totals*	**$2.4**	**$2.9**	**$3.5**	**21.1%**

**May not sum due to rounding*

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, mitigation, and response to significant emergency incidents that may adversely affect service to customers, company assets, and employees. This includes providing planning, training, and exercise support (e.g., grid exercises, wildfire exercises executing the Public Safety Power Shutoff (PSPS) Plan, annual Incident Management Team (IMT) outage drill, etc.) to recover critical functions as quickly as possible and in compliance with all regulatory requirements. This department establishes business continuity and emergency management plans and procedures; conducts risk and business impact assessments; develops training programs and materials; and 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. How do BCEM costs for 2020 compare with prior year actuals?

A. BCEM costs for 2020 are below actuals for both 2018 and 2019.[4] The decrease in BCEM costs from 2018 and 2019 to 2020 results from the unsustainable suspension of some program activity costs for 2020. This decrease is not reflective of overall trends that are causing increased pressure on BCEM and both 2021 and 2022 costs are forecasted to exceed costs in prior years.

Q. What trends are causing increased pressure on BCEM?

A. Climate change has resulted in more extreme weather and wildfire impacts, particularly in Oregon and PGE's service territory. Recent civil unrest has had impacts on operations and resulted in a need for additional investment in situational awareness. Further, COVID-19, the 2020 Oregon wildfires, and the severe 2021 winter ice and snowstorms that resulted in two

[4] BCEM expenses totaled approximately $1.1 million in 2018 and $1.0 million in 2019. See PGE Exhibit 401 for further detail

Oregon State of Emergency declarations underscore the critical need for enhanced planning and capabilities, as well as a flexible workforce to manage all-hazards type of incidents.[5]

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. For example, PGE recently completed a business impact analysis of all its business processes and is developing comprehensive business continuity plans for its critical business areas.

When comparing 2020 actuals with 2021 and 2022 forecasts, the increase in BCEM costs is due to: 1) resumption of normal programmatic spending, which decreased in 2020 as a result of unsustainable and temporary COVID-19 recession budget reductions; and 2) recognition of the need to address aforementioned increasing pressures on the BCEM department. While the increase in BCEM costs is small (i.e., approximately $0.5 million compared to 2018 and 2019 average expense), 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.

Q. How is PGE continuing to address issues for 2021 and 2022?

A. BCEM programs at PGE continue to develop and evolve to meet and respond to a continually changing environment. In 2021, we are hiring one additional BCEM employee and backfilling one position left open in 2020 to enhance our planning capabilities. As mentioned, PGE recently completed a business impact analysis and is developing business continuity plans for

[5] More detail at https://www.oregon.gov/gov/Documents/executive_orders/eo_21-01.pdf and https://www.oregon.gov/gov/Documents/executive_orders/eo_21-02.pdf

its critical business areas. Emergency Operating Procedure (EOP-008)[6] is the regulatory requirement directly associated with business continuity planning; however, other standards, such as EOP-010,[7] highlight the need for business continuity planning to ensure continuation of critical business processes in the face of disaster.

Q. What are some recent examples of BCEM responding to this need?

A. During the Oregon wildfires, PGE managed four separate incidents simultaneously – high wind outage event, a PSPS, wildfire impacts to service territory and hydro facilities, and the COVID-19 pandemic - using the National Incident Management System Incident Command System (ICS) process. This ICS structure and the use of liaisons, as well as hosting coordination calls with stakeholders, was critical to PGE being interoperable with public sector emergency operations centers and fire incident management teams, and greatly enhanced operations and safety. Further, during the historic wave of ice storms in February 2021, PGE's IMT was virtually activated for 16 straight days to support storm response and recovery operations, which ultimately resulted in the restoration of power to nearly 740,000 customers. PGE's IMT coordinated closely with county emergency managers and state of Oregon Emergency Support Function-12[8] in setting response and recovery priorities, as well as communicating essential customer information to enhance the conducting of public sector wellness checks.

Q. Why are security costs seeing a slight increase in 2022?

A. The primary driver behind increasing security costs in 2022 is the additional labor needs to staff our Integrated Security Operations Center (ISOC). We are developing a more centralized

[6] More detail at https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf
[7] More detail at https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf
[8] More detail at https://www.energy.gov/ceser/esf-12-events

capability as we move into the Integrated Operations Center (IOC) and taking on additional monitoring responsibility across the system. Specifically, we are expanding our coverage in the ISOC to have 24/7 on-site monitoring and response capability. Further, PGE's World Trade Center (WTC) downtown offices have experienced a trend of increasing encounters with individuals engaged in civil unrest, requiring additional investment in our security organization. See PGE Exhibit 800 for more detail on PGE's ISOC, and the relationship between individuals engaged in civil unrest in downtown Portland and the need for additional security investments.

C. 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 2020 to 2022?

A. The estimated increase in net benefit costs from 2020 to 2022 is approximately $7.2 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 300 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 after labor loadings apply certain amounts of these costs to capital projects and "below-the-line" activities. PGE Exhibit 300 explains the gross corporate forecast for these costs.

Q. How does PGE mitigate cost increases for employee benefits?

A. As discussed in PGE Exhibit 300, 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.

D. Finance and Accounting Services

Q. How much do you expect finance and accounting (F&A) costs to increase from 2020 to 2022?

A. PGE's costs for these F&A services are forecast to increase from approximately $10.3 million in 2020 to $12.1 million in 2022, an increase of approximately $1.7 million.

Q. Please briefly describe the primary drivers behind this increase.

A. This increase is largely due to organizational restructuring and subsequent increase in labor, which is needed to support various functions in the F&A area, along with an increase in outside services support. Specifically, during 2020, there were seven unfilled positions intentionally frozen in response to the unprecedented COVID-19 pandemic and ensuing recession. As this reduction was temporary and unsustainable, four of these positions have already been filled in 2021, with one additional out of the seven originally left open in 2020 expected to be filled in 2021. As such, while PGE was able to permanently reduce two of the seven positions, five are included in the 2022 test year forecast, reflecting the level of support necessary to resume normal business operations. Please note, these 2020 reductions are partially obscured in the data due to organizational restructuring, which moved certain costs from other areas, such as performance management, into the F&A services group. As a result, while F&A incorporated unstainable reductions into 2020, when comparing both F&A and performance management areas together, the total labor costs for 2022 are below the 2019 amounts.

Q. Why are outside services increasing for F&A?

A. The outside services increase is largely driven by the resumption of normal business activity in 2021 and 2022 compared with unsustainable cuts in 2020 as a result of COVID-19. There are also some unavoidable cost increases impacting the 2021 and 2022 forecast, which we describe below.

Q. If PGE made unsustainable reductions to its outside services and non-labor budgets in F&A in 2020, why are amounts in 2020 effectively flat compared with 2019?

A. While PGE did make targeted and unsustainable reductions to the F&A non-labor budget for 2020 of approximately $0.5 million, these reductions are obscured by an approximate $0.3 million credit amount incorrectly recorded to F&A in 2019 and by unexpected and unbudgeted increases to finance and accounting consulting services during the year. The credit amount in 2019 was related to spending card rebates that are normally recorded and budgeted within FERC account 456 (Other Revenue) but were incorrectly recorded in F&A accounts for 2019. The result is that 2019 costs appear lower than they otherwise would. PGE has recorded this amount to FERC account 456 for all other years and continues to budget this rebate within FERC account 456.

Q. Please describe the unavoidable increases for 2021 and 2022 within F&A.

A. The actual increase in forecasted costs for 2021 and 2022 from PGE's more normalized spending levels in 2018 and 2019 are due largely to the resumption of activities deferred in 2020, coupled with base inflation and an increased level of audit fees and audit support,[9] tax consultant fees and support, and annual upgrade costs for Workiva "Wdesk" software used for financial reporting analyses. As rules and regulations continue to evolve, the nature and scope of auditing services continues to evolve, resulting in current and future increases to these costs. Additionally, because of PGE's relationship with our third-party auditors and the unprecedented COVID-19 pandemic, we were able to pause inflationary increases on these services for 2020. However, this means that PGE is incurring two years of inflation for these services in 2021. The increase to Wdesk software, which PGE uses for Securities and Exchange Commission and FERC reporting purposes is due largely to changes in FERC reporting requirements. Specifically, FERC has adopted the XBRL[10] data standard for reporting purposes and energy companies are expected to use software that supports this standard beginning later in 2021.

Q. Are there any offsets to the increases in F&A?

A. Yes. As we discussed above in Section II, PGE is reflecting an approximate $1.8 million budget reduction within the Office of CFO and Treasurer. While this targeted reduction is reflected in PGE's CFO department, it represents approximately 83% of the total CFO department forecast for 2022 and will not be fully realized within that department. A large

[9] These audit fees are unrelated to the August 2020 trading losses.
[10] https://www.xbrl.org/the-standard/what/an-introduction-to-xbrl/

portion of this reduction to PGE's request will ultimately be realized within PGE's F&A departments as they report up to PGE's Office of CFO and Treasurer. When taking this into account, the 2022 forecast in the F&A area is effectively flat compared with 2020 actual costs.

E. Facilities and Rent

Q. Please describe the apparent increase to facilities and rent costs for 2022.

A. The A&G forecast for facilities and rent appears to increase from approximately $4.6 million in 2020 to $6.9 million in 2022. As we explain below, however, this is due largely to changes to the accounting and mapping of costs, coupled with departmental changes resulting in the appearance of an increase to both PGE's rent and facilities costs. As we highlight in PGE Exhibit 800, PGE's WTC rent costs are in fact decreasing both within A&G and in total, due primarily to the movement of employees to the IOC.

Q. How have changes to facilities impacted costs from 2020 to 2022?

A. There are two primary reasons why PGE's facilities costs are higher than 2020 actual amounts:

1. Beginning in 2021, certain labor costs that were previously allocated to general plant maintenance are now recorded within facilities cost categories (Figure 1 below shows this shift in labor costs).[11] When taking this shift into account, facilities labor is below 2019 costs and only slightly higher than 2020 costs.
2. The new IOC facility results in more overall square footage to maintain, which increases facility maintenance costs overall. This amounts to an approximate $0.4 million increase for 2022 (see PGE Exhibit 800 for more details regarding the move to the IOC).

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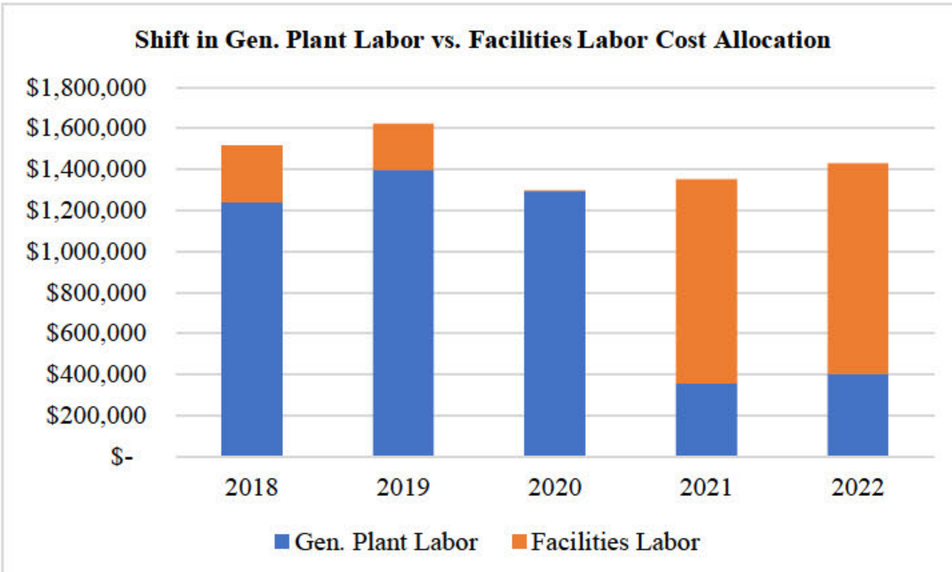
[11] The shift in labor costs is attributable to union employees who had previously charged their time to general plant maintenance prior to 2021. This work is now performed by non-represented employees who charge their time to the facilities cost category.

Additionally, as COVID restrictions began in the spring of 2020, PGE put several potential projects on pause in an effort to temporarily reduce costs. These reductions were temporary and normal activities have since resumed.

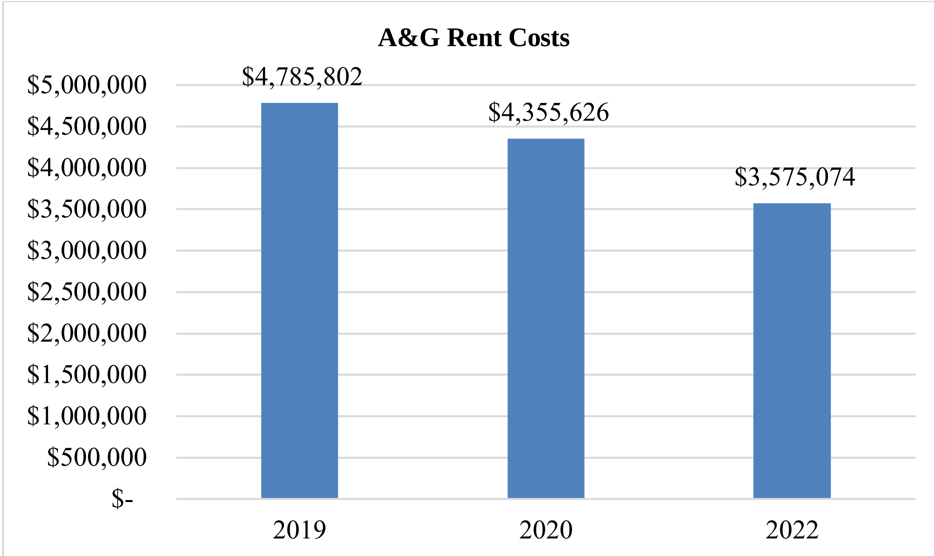
Figure 1



Q. Please explain rent costs within A&G.

A. As discussed in PGE Exhibit 800, PGE's overall WTC rent expense is expected to decrease from $8.5 million in 2020 to $6.2 million in 2022, a reduction of approximately $2.4 million. With the shift of PGE employees from the WTC to the IOC, the percentage of PGE WTC rent that is allocated to A&G is expected to increase from 51% in 2020 to 58% in 2022. However, overall rent costs within A&G are still expected to decrease from $4.4 million in 2020 to $3.6 million in 2022 (See PGE Exhibit 404 for further detail).

Figure 2



Q. How does PGE's accounting of rent costs affect the 2020 to 2022 variance in total facilities and rent costs described above?

A. Due to how rent costs were previously allocated and recorded within PGE's general ledger, A&G rent appears to be increasing. More specifically, portions of A&G-allocated rent for the WTC were posted to accounts other than the account used for recording rent expense. After recognizing this issue and reviewing the FERC chart of accounts, PGE determined that the portion of WTC rent to be allocated to A&G should correctly be posted to the A&G rent expense account – not the A&G non-labor expense account, the amounts for which are not separately identifiable. Therefore, the actual A&G rent amounts provided in PGE Exhibit 404 accurately capture all A&G rent expense for 2019 and 2020, the years in which a portion of A&G rent was not correctly allocated to PGE's rent expense account.

F. Research & Development

Q. How did PGE establish its forecast of Research and Development (R&D) cost?

A. PGE established its R&D forecast in accordance with Commission Order No. 18-464, which specifies that:

> PGE will determine the percentage of fixed Transmission and Distribution ("T&D") and Generation Operations and Maintenance ("O&M") costs (excluding Boardman) in the test year forecast that $2.6 million represents and the Stipulating Parties agree to apply that percentage from this rate case to determine a presumptive reasonableness of R&D costs in PGE's next three rate cases, or 10 years, whichever occurs first.[12]

Q. How did you calculate the R&D forecast based on this requirement?

A. By applying this method, we determine that $2.6 million represents approximately 0.825% of final UE 335 T&D and generation fixed O&M (excluding Boardman). Applying 0.825% to the 2022 forecasted T&D and generation fixed O&M produces an adjusted R&D expense of approximately $2.7 million for the 2022 test year.

[12] Commission Order No. 18-464, Appendix A, pages 2-3.

IV. Information Technology

Q. Please summarize the activities or functions that 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 its 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[13] to increase?

A. We forecast IT O&M costs to increase by approximately $5.2 million, from $72.3 million in 2020 to $77.5 million in 2022 as shown in Table 5 below. Because these costs relate to all areas of PGE's operations, they are directly charged or allocated to appropriate operating areas and appear as part of each area's O&M costs. Consequently, we discuss IT as a whole in this section of the testimony rather than just the portion charged to A&G.

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

Table 5
Total IT Costs ($ millions)

Category	2019 Actuals	2020 Actuals	2021 Actuals	2022 Forecast	2020-2022 Delta
Direct Charges to Operating Areas	$18.9	$16.2	$13.4	$14.3	$(1.9)
Allocated Charges to Operating Areas	$55.7	$43.2	$48.1	$48.5	$5.4
Subtotal IT Incurred	**$74.6**	**$59.3**	**$61.5**	**$62.8**	**$3.5**
Labor Loadings	$13.7	$13.0	$14.3	$14.7	$1.7
Total IT*	**$88.3**	**$72.3**	**$75.7**	**$77.5**	**$5.2**

**May not sum due to rounding*

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

A. As shown in Table 5 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 405 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 relate to total compensation, we discuss them in PGE Exhibit 300 rather than here. PGE Exhibit 200 provides detail on payroll taxes. Finally, PGE submits detail 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. Why do labor loadings increase by $1.4 million?

A. Because labor loadings are calculated amounts, the increase in labor loadings is due to the increase in IT O&M labor on which they are based. The loadings effectively move costs from certain sections of the income statement to other sections. However, the net impact of this on PGE's revenue requirement is zero.

Q. What are the major drivers of the forecasted O&M cost increase from 2020 to 2022?

A. Three primary drivers affect the variance between 2020 actuals and 2022 forecast of IT O&M:

- Wage and salary escalations as discussed in detail in PGE Exhibit 300 Section III, B.
- Temporary and unsustainable reductions in 2020 O&M costs designed to preserve adequate cash flows in response to the rapid economic downturn and financial hardship/liquidity crisis facing customers due to the COVID-19 pandemic. In IT, these reductions were met largely by delaying 2020 O&M initiatives and hiring. Please see Table 5 above to see the overall change in the IT expenses between 2019 and 2020.
- Increased software and hardware license 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, data strategy and cyber security.

Q. When comparing 2019 actuals to 2022 forecast, there is a decrease in O&M costs. Can you please explain the source of the difference?

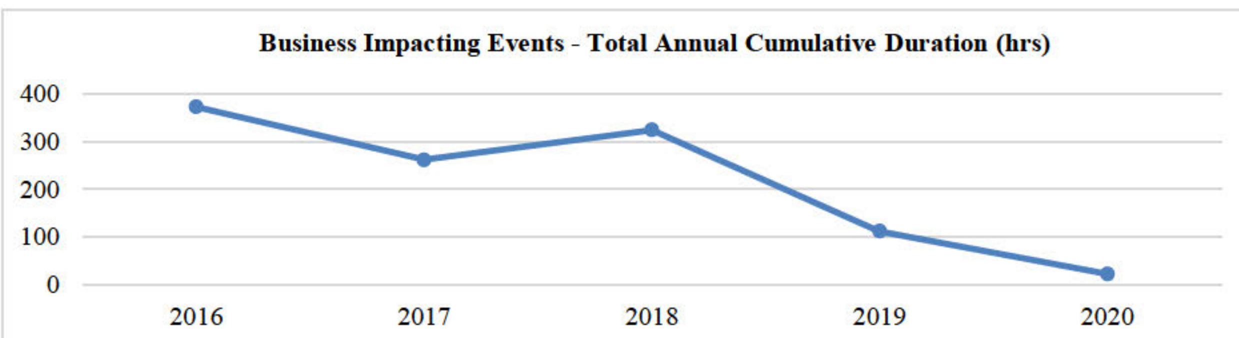
A. Since 2019, IT reduced the labor budget and permanently closed nearly 50 positions resulting in savings of $8.4 million. Of the closed positions approximately 10 employees were laid off while the remaining positions were not filled when we closed them.

- One of the main areas of cost reduction came from Customer Operations. PGE formed strategic partnerships with companies like Google and Amazon to take advantage of scalable and resilient infrastructure to support our customers' experience at lower costs than in-house solutions. External partnerships increased automation and reduced or eliminated the need for IT roles that focused on manual operations.
- Another area that has seen labor cost reductions is in the IT Service Desk & Desktop Support area. Due to recent changes to the work management tool, we have improved knowledge base and workflow processes. Previously one desktop group provided core desktop support to the entire company, while another group provided specialized support for field operations. We improved skills sets and processes of both groups and merged them under one management. Similarly, we had our Service Desk working 9/5 and an IT System monitoring group working 24/7. We changed the skillsets and combined the groups; as a result, the team became more efficient and increased the level of service for the IT Service Desk from 9/5 support to 24/7. In addition to the staff consolidation, we were able to add some process automation and self-services which reduced manual workload. We also shifted some of our IT Service Desk level 1 support to using contractors that were less expensive, which resulted in labor savings without a loss of service.

Q. Does the reduction in labor lead to reduced performance?

A. No. The IT department continues to reduce the frequency and duration of IT disruptions for customers and across the enterprise for employees. With improved IT operations and a new IT service management and process workflow system in place, we were able to significantly reduce the number of business-impacting events. Business impacting events are any system failure that prevents business from being accomplished and varies from a small application no longer functioning to a large business process being prevented from occurring. Following 70 business-impacting events in 2017, we lowered the number to 30 events in 2018 and 21 in 2019. Our goal is to have zero events. Figure 3 below shows the decrease in event hours over the years.

Figure 3



V. Summary

Q. Please summarize your request for A&G in this filing.

A. We request that the Commission approve PGE's forecast of $186.9 million in A&G costs in the 2022 test year. This represents a $6.1 million decrease from 2020 actuals, primarily due to PGE implementing budget reductions and targeted savings across several functional areas to mitigate customer price impacts.

VI. 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

Exhibit	**Description**
401	Summary of A&G Costs
402	PGE Insurance Policies List
403C	Summary of Insurance Costs
404	WTC Rent Allocation
405	Direct and Allocated IT Charges

A&G Summary	Costs						
Category	2018 Actuals	2019 Actuals	2020 Actuals	2021 Budget	2022 Forecast	2020 to 2022 $ Delta	2020 to 2022 Annual %
Major Functional Areas							
Accounting/Finance	10.3	10.3	10.3	11.7	12.1	1.7	8.0%
Business Support Services	0.8	1.8	1.5	1.1	1.1	-0.4	-13.2%
Corp Communications/Public Affairs	3.1	3.4	3.7	3.3	3.1	-0.6	-8.1%
Corporate Governance	5.7	6.0	6.8	4.0	4.1	-2.7	-22.6%
Corporate R&D	2.0	2.5	2.4	2.6	2.7	0.3	5.7%
Environmental Services	2.6	2.5	2.1	1.8	1.8	-0.2	-5.8%
Facilities/Rent	7.4	5.9	4.6	7.7	6.9	2.3	22.3%
Governmental Affairs	1.5	1.5	1.5	1.5	1.6	0.0	0.8%
HR/Employee Support (net of capital allo	13.9	12.1	10.3	11.0	11.2	0.9	4.3%
Hydro Licensing and Support	0.1	0.0	0.0	0.0	0.0	0.0	449.0%
INSURANCE	12.3	13.6	12.6	15.1	17.9	5.4	19.5%
IT: Direct & Allocated	13.6	15.5	13.9	15.7	16.3	2.5	8.5%
Legal	7.3	9.2	7.5	6.6	6.9	-0.7	-4.7%
Performance Management	2.2	1.8	1.5	1.3	1.4	-0.1	-4.8%
Regulation	3.1	2.7	2.9	3.3	3.4	0.5	9.1%
Business Continuity (BCEM)	1.1	1.0	0.8	1.3	1.6	0.8	39.0%
Security	1.6	1.8	1.5	1.6	1.9	0.3	10.5%
Supply Chain/Contract Services/Purchas	2.1	2.2	2.3	0.9	1.0	-1.4	-35.4%
Subtotal	90.9	93.8	86.3	90.6	94.9	8.6	4.9%
Other A&G Costs							
Benefits (net of capital allocs.)	57.6	56.1	52.3	58.0	59.6	7.2	6.7%
Corporate Allocations (net)	-21.6	-7.3	-4.9	-0.9	-1.9	3.0	-37.7%
Corporate Cost Reductions	0.0	0.0	0.0	-4.4	-4.4	-4.4	
General Plant Maint.	2.9	3.1	2.6	1.6	2.2	-0.4	-8.4%
Incentives	27.7	32.1	29.1	39.9	13.7	-15.4	-31.5%
LC Fees, Revolver Fees, Margin Net Int.	1.4	2.0	2.1	2.3	2.0	-0.1	-1.8%
Membership Costs	3.4	3.7	2.5	3.4	3.5	1.0	18.7%
Regulatory Fees	8.1	8.1	8.3	8.3	10.3	2.0	11.5%
Severance	3.5	6.1	8.4	0.0	0.0	-8.4	-100.0%
Total Labor Loadings to A&G	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total PTO to A&G	6.3	6.7	6.3	6.8	7.1	0.8	5.9%
Subtotal	89.3	110.6	106.7	115.0	91.9	-14.8	-7.2%
TOTAL A&G	180.1	204.4	193.0	205.6	186.9	-6.1	-1.6%

PGE's Insurance Policies

Insurance Policy	Description
All Risk Property	PGE's main All-Risk property insurance program is led by FM Global 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 $2.5 million deductible.
Renewable 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 $1.3 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 $1 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 $185 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 $15 million with a $.25 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.
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 $800 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 403 contains confidential information and is subject to General Protective Order 21-206.

Information provided in electronic format only.

WTC Rent Allocation

BU	OU	ACCT	AWO	DESCRIPTION	2019 Allocation %	2020 Allocation %	2022 Allocation %	2020-2022 % Change	2019 Allocated $	2020 Allocated $	2022 Allocated $	2020-2022 $ Change
PGE01	18100	1070002	2000010754	T&D Construction O/H	1.43%	1.60%	0.40%	-1.20%	127,752	136,433	24,647	(111,786)
PGE01	18100	1070002	7000010811	Generation Construction O/H	6.30%	6.85%	1.73%	-5.12%	562,825	584,104	106,599	(477,505)
PGE01	18100	1840004	7000000602	IT Service Provider	25.38%	29.36%	24.40%	-4.96%	2,267,382	2,503,547	1,503,478	(1,000,069)
PGE01	18100	1840016	7000000602	PAD			3.91%	3.91%	-	-	240,926	240,926
PGE01	18100	1860001	7000000159	PGE Foundation	0.08%	0.07%	0.05%	-0.02%	7,147	5,969	3,081	(2,888)
PGE01	18100	1860001	7000000160	Salmon Springs	0.62%	0.62%		-0.62%	55,389	52,868	-	(52,868)
SSH01	89100	4171001	7000000602	Salmon Springs			0.58%	0.58%	-	-	35,738	35,738
PGE01	18100	5570003	7000000602	Generation Plant Support	11.67%	9.38%	9.77%	0.39%	1,042,567	799,839	602,007	(197,831)
PGE01	18100	9200001	7000000602	A&G	11.21%	14.76%	0.00%	-14.76%	1,001,472	1,258,595	-	(1,258,595)
PGE01	18100	9310001	7000000602	Rent General Facility	41.65%	35.82%	57.65%	21.83%	3,720,901	3,054,395	3,552,275	497,880
PGE01	18100	4171003	7000000381	Non-Utility	0.61%	0.50%	0.48%	-0.02%	54,496	42,635	29,577	(13,059)
PGE01	18100	9302001		COY SP CONS OH & A&G	0.05%	0.00%	0.00%	0.00%	4,467	-	-	-
PGE01	91100	2300002	3000000633	Trojan ARO	0.14%	0.24%	0.44%	0.20%	12,507	20,465	27,112	6,647
PGE01	91100	9350001	7000000602	Trojan O&M	0.00%	0.00%	0.00%	0.00%	-	-	-	-
PGE01	92100	1070002	7000010813	Boardman Construction OH	0.02%	0.06%	0.00%	-0.06%	1,787	5,116	-	(5,116)
PGE01	92100	9200002	7000000602	Boardman A&G	0.26%	0.21%	0.00%	-0.21%	23,228	17,907	-	(17,907)
PGE01	96100	1070002	7000010815	Pelton Construction OH	0.03%	0.12%	0.03%	-0.09%	2,680	10,232	1,849	(8,384)
PGE01	96100	9200002	7000000602	PLTN MNG RELATION	0.29%	0.16%		-0.16%	25,908	13,643	-	(13,643)
PGE01	96100	9310001	7000000602	PLTN MNG RELATION			0.17%	0.17%	-	-	10,475	10,475
PGE01	99100	1070002	7000010814	RB Construction OH	0.10%	0.12%	0.19%	0.07%	8,934	10,232	11,707	1,475
PGE01	99100	9200002	7000000602	RB Other	0.16%	0.13%		-0.13%	14,294	11,085	-	(11,085)
PGE01	99100	9310001	7000000602	RB Other			0.20%	0.20%	-	-	12,324	12,324
				Total	**100.00%**	**100.00%**	**100.00%**	**0.00%**	**8,933,735**	**8,527,067**	**6,161,796**	**(2,365,271)**

	2019 %	2020 %	2022 %	Δ 2020-2022	2019 $	2020 $	2022 $	Δ 2020-2022
Total Rent Allocated to A&G (FERC 920-935)	**53.62%**	**51.08%**	**58.02%**	**6.94%**	**$ 4,790,269**	**$ 4,355,626**	**$ 3,575,074**	**$ (780,552)**
Total Rent Allocated to 9310001	**41.65%**	**35.82%**	**58.02%**	**22.20%**	**$ 3,720,901**	**$ 3,054,395**	**$ 3,575,074**	**$ 520,679**

IT Ex 405	a-Dec - 2018	a-Dec - 2019	a-Dec - 2020	Dec - 2021	Dec - 2022	Delta (Test Year - Base Year)	Annual % Delta (Test Year - Base Year)
Generation							
IT Direct	406	1,686	103,749	3,615	3,719	(100,031)	(81.1%)
IT Allocated	10,678,736	15,581,859	10,821,279	7,773,745	7,771,828	(3,049,450)	(15.3%)
IT Deferral	312,972						
Subtotal Generation	10,992,114	15,583,545	10,925,028	7,777,360	7,775,547	(3,149,481)	(15.6%)
Power Ops							
IT Direct	1,617,440	2,037,314	1,826,373	2,326,128	2,385,332	558,959	14.3%
IT Allocated	1,770,716	2,246,683	2,383,333	6,026,301	6,110,442	3,727,110	60.1%
Subtotal Power Ops	3,388,157	4,283,997	4,209,705	8,352,429	8,495,774	4,286,069	42.1%
Transm.							
IT Direct	210,226	1,235,781	1,176,555	381,166	389,493	(787,061)	(42.5%)
IT Allocated	1,748,945	2,599,104	2,174,044	943,384	955,040	(1,219,004)	(33.7%)
IT Deferral	56,099						
Subtotal Transm.	2,015,270	3,834,885	3,350,599	1,324,549	1,344,534	(2,006,065)	(36.7%)
Distr.							
IT Direct	5,094,307	4,847,964	3,924,788	1,756,303	1,796,810	(2,127,978)	(32.3%)
IT Allocated	18,580,222	12,463,247	7,593,292	11,643,724	11,797,661	4,204,369	24.6%
IT Deferral	415,443						
Subtotal Distr.	24,089,972	17,311,211	11,518,080	13,400,027	13,594,471	2,076,391	8.6%
Cust Service							
IT Direct	186,702	176,817	158,756			(158,756)	(100.0%)
IT Allocated	2,481,906	2,484,567	2,434,888	3,166,796	3,211,011	776,124	14.8%
Subtotal Cust Service	2,668,607	2,661,383	2,593,643	3,166,796	3,211,011	617,368	11.3%
Cust Accounts							
IT Direct	7,130,860	13,210,318	11,190,890	14,366,121	14,932,826	3,741,936	15.5%
IT Allocated	13,498,082	14,361,149	12,620,369	13,341,513	13,527,792	907,423	3.5%
IT Deferral	527,466						
Subtotal Cust Accounts	21,156,409	27,571,467	23,811,260	27,707,635	28,460,618	4,649,359	9.3%
A&G							
IT Direct	2,348,578	1,952,379	2,115,140	(1,755,828)	(1,318,607)	(3,433,747)	(21.0%)
IT Allocated	12,997,119	15,123,542	13,820,687	15,761,663	15,982,856	2,162,169	7.5%
IT Deferral	424,821						
Subtotal A&G	15,770,519	17,075,921	15,935,827	14,005,835	14,664,249	(1,271,578)	(4.1%)
						0	
Total							
IT Direct	16,588,521	23,462,259	20,496,251	17,077,505	18,189,573	(2,306,678)	(5.8%)
IT Allocated	61,755,725	64,860,151	51,847,892	58,657,125	59,356,632	7,508,740	7.0%
IT Deferral	1,736,800						
Subtotal Total	80,081,046	88,322,410	72,344,143	75,734,629	77,546,205	5,202,062	3.5%

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Customer Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

John McFarland
Larry Bekkedahl

July 9, 2021

Table of Contents

I. Introduction and Overview

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

A. My name is Larry Bekkedahl. I am Senior Vice President of Advanced Energy Delivery. My name is John McFarland. I am Vice President and Chief Customer Officer.

Our qualifications appear 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 2022 test year and compare them to 2020, which represents PGE's most recent actual results. We discuss the Flexible Load Plan (FLP) proposal, creation of the Transportation Electrification (TE) program, and the costs as well as the customer benefits associated with that work. Finally, we will discuss payment options and the proposal to offer fee free debit and credit card payments to small non-residential customers.

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 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:

[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 902-908).

- 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 filed with the Public Utility Commission of Oregon (Commission or OPUC).
- 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 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 falling in the first quarter of 2021. PGE is currently ranked No. 2 in the nation for utility customer experience, moving up from No. 10 in 2020, per Forrester's 2021 Customer Experience Index study. Customer expectations continue to increase in each of our three segments and customers increasingly expect PGE to understand their needs and offer solutions that address 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 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 providing timely and accurate billing, offering payment options, start/stop/move service support, large customer new service coordination, enrollment in energy programs, and supporting 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 a local community resource center (which was activated to support customers during the Public Safety Power Shutoff), 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 promote and coordinate a variety of programs, such as demand response, renewable options, and energy efficiency, 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. Has the Customer Service organization recognized and responded to changing customer needs during the COVID-19 pandemic?

A. Yes. In response to the challenges faced by our customers during the pandemic, PGE adjusted customer service operations in several ways:

- Paused the assessment of late fees on past-due balances in support of customers affected by the pandemic;
- Paused service disconnections for non-payment;
- Launched a proactive customer outreach program to help customers with payment arrangements, manage their energy usage and connected them to energy assistance programs for federal, state, and non-profit funding;
- Provided information to business customers about grants and programs that support small businesses and various industries;
- Supported business customers by offering Time Payment Agreements and temporarily waived bank card fees;
- Developed bill assistance programs to assist customers with growing past due balances;
- Partnered with a municipality to offer bill assistance to small business customers with past due balances; and
- Expanded the number of supported languages to effectively reach all impacted customers with assistance messaging.

Q. How is your testimony organized?

A. In Section II, we explain PGE's request for forecasted 2022 O&M costs in comparison to 2020 actual costs. In Section III we discuss the FLP and the effect it will have on base rates. In Section IV, we discuss the development of our new TE program and the benefits that it will bring to PGE customers. Section V provides information on payment options and a proposal to offer fee free card payments to small business customers. We provide concluding remarks in Section VI, and our qualifications are summarized in Section VII.

II. Operations and Maintenance Costs

Q. What is PGE's forecast of Customer Service O&M costs for the 2022 test year?

A. PGE forecasts approximately $90.0 million in total Customer Service O&M for 2022, including uncollectible expense, which is a revenue sensitive cost. This represents a $12.9 million increase relative to PGE's 2020 actual costs. The overall increase to Customer Service is attributed primarily to cost escalation,[2] new programs, and TE work. Table 1 summarizes these costs, which are discussed in more detail below.

Table 1
Customer Service O&M Expenses ($ Millions)

Category	2019 Actuals	2020 Actuals	2022 Forecast	(2022-2020) Delta*
Labor	$32.2	$27.9	$34.0	$6.0
Non-Labor	$12.4	$15.6	$17.5	$1.8
Subtotal*	**$44.6**	**$43.6**	**$51.4**	**$7.8**
Information Technology	$30.2	$26.4	$31.7	$5.3
Subtotal*	**$74.8**	**$70.0**	**$83.1**	**$13.1**
Uncollectibles	$2.2	$7.1	$6.9	$(0.2)
Total Base Business Costs*	**$77.0**	**$77.1**	**$90.0**	**$12.9**

** May not sum due to rounding*

Q. What accounts for the increase in labor costs from 2020 to 2022?

A. Reasons for O&M labor increases in customer service include the following:

- Approximately $2.0 million increase in labor due to hiring delays. From 2019 to 2020 while there were reductions made that will be sustainable long term, there were also some temporary and unsustainable reductions that were designed to preserve adequate cash flows in response to the rapid economic downturn facing customers due to the COVID-19 Pandemic. In 2022 the labor resources are

[2] PGE Exhibit 200 provides the cost escalation factors that PGE used in developing its 2022 test year forecast. PGE Exhibit 300 provides additional detail regarding labor escalation.

projected to return to pre-pandemic levels, less the sustainable reductions, which together results in an apparent increase between 2020 and 2022. Table 1 above shows the reduction in labor expenses in 2020 as compared to 2019 and 2022.

- Approximately $1.7 million for development and support of the new TE program is further discussed in Section IV, below.
- Wage and salary increases account for $1.1 million and are discussed in further detail in Exhibit 300.
- Approximately $0.8 million to account for labor currently subject to deferral and recovered through PGE Schedule 135. See further discussion in Section III.
- Approximately $0.5 million for limited duration employees hired to attract labor in a tight labor market and are offset in non-labor expenses.

Q. Please explain the forecasted increase in non-labor costs from 2020 to the 2022 test year forecast.

A. In addition to cost escalation, the primary increase in Customer Service non-labor costs from 2020 to 2022 is related to TE as well as an increase related to bank card payment options.

- Increases in the TE program amount to $1.8 million and are discussed in Section III below.
- An increase of $1.6 million related to payment options discussed in greater detail in Section V below.
- Other changes are in customer services; we have seen decreases in Print and Mail Services as customers are choosing to do more business over digital channels. However, there are slight increases in electronic bill payments, customer digital channels, and Key Customer Group.

Q. Do you address IT costs in this testimony?

A. Yes. The increase in IT expense is predominately driven by hiring delays designed to preserve cash flow during the pandemic. This disproportionately impacted customer service relative to other functional areas because the hiring delays occurred in customer driven IT positions. There were also increases stemming from higher use of licenses in the customer service area. IT costs are charged or allocated to all operating areas of the company and further details are discussed in PGE Exhibit 400, Section IV.

Q. How did you forecast PGE's uncollectible expense for 2022?

A. Uncollectible expense typically increases during periods of economic downturn. History has shown that in prior years of similar economic downturns, uncollectible rates can reach 0.5% or higher. In reviewing the effects of increasing our uncollectible expense, we found it would have caused upward cost pressures to customers and we chose not to increase this value at this time. Consequently, we propose to continue using the 0.32635% uncollectible rate approved in PGE's most recent general rate case (Docket No. UE 335).

III. Flexible Load Plan (FLP)

Q. Please describe the FLP in more detail and how it relates to this general rate case.

A. In December 2020[3] we submitted PGE's FLP that entails a multi-year proposal and budget for flexible load activity in pursuit of the demand response goals specified in PGE's 2019 Integrated Resource Plan (Docket No. LC 73). The intent of the FLP is to provide transparent portfolio-level planning and cost analysis, and to address the full value of PGE's flexible load resources to make a resilient and integrated grid. In the FLP filing, PGE proposes to subsequently file a multi-year plan, which would combine five demand response pilots currently under deferral in four separate dockets into one docket and one cost recovery approach. To see detailed information about FLP please see PGE Exhibit 600.

Q. What are the existing dockets that will be associated with FLP?

A. There are several open dockets related to FLP in which PGE is participating:

- UM 1514: Non-Residential Demand Response Energy Partner Program
- UM 1827: Multifamily Water Heater Pilot
- UM 1708: Smart Thermostat Pilot and Flex 2.0 - Peak Time Rebate and Time of Use
- UM 2078: Residential Battery Energy Storage Pilot
- UM 1976: Demand Response Testbed Pilot

Q. Please describe what FLP costs are included in your 2022 O&M forecast?

A. As described above, we are incorporating only the labor costs associated with development and management of the FLP programs. To effectively manage five programs, labor resources

[3] UM 2141 Flexible Load Plan, https://edocs.puc.state.or.us/efdocs/HAS/um2141has132229.pdf

need to be flexible to perform similar functions across all programs. The inclusion of labor resources in the GRC represents: 1) a shift from existing demand response deferrals, which reflects no overall change in prices for PGE customers; and 2) additional labor to implement and manage PGE's plan to triple demand response capacity from 2020 to 2024. The incremental labor represents ongoing positions that include project managers, program implementers, and community outreach specialists. Non-labor costs associated with the FLP, such as participation incentives, third-party services, and program evaluation will remain separate from base prices and be addressed in the FLP proceeding, Docket No. UM 2141. We believe this labor/non-labor separation is appropriate because labor is more flexible and can be applied to a variety of demand response programs, whereas the non-labor components are dedicated to individual programs and only for specific activities. This cost represents the additional labor needed to achieve and manage the level of demand-side capacity that PGE is targeting by 2024.

Q. Where can I find more details on the FLP program?

A. Please see further discussion of FLP cost recovery in PGE Exhibit 600.

IV. Transportation Electrification (TE)

Q. Please provide an overview of existing state policies in support of electric transportation.

A. In 2016, the Oregon Legislature adopted Senate Bill (SB) 1547[4], supporting electric utility investment and participation in transportation electrification through programs that accelerate TE[5], expand access to Electric Vehicles (EVs) for customers[6], and provide efficient grid integration[7]. After adopting SB 1547, the Oregon legislature and Governor's office adopted additional policies to encourage the electrification of the transportation sector. Specifically, SB 1044 established statewide goals for zero-emission vehicle (ZEV) adoption, including that the vehicle market must be transformed by 2035 to meet statewide GHG reduction goals:

- 2020 – 50,000 Registered ZEVs;
- 2025 – 250,000 Registered ZEVs;
- 2030 – 25% of Registered Vehicles are ZEVs and 50% of new vehicle sales are ZEV; and
- 2035 – 90% of new motor vehicle sales will be ZEV.

House Bill 2165 passed in 2021 further expanding utility's role in TE and defining infrastructure measures. Further, the Governor's Executive Order 20-04[8] states, "It is in the interest of utility customers and the public generally for the utility sector to take actions that result in rapid reductions of GHG emissions, at reasonable costs, to levels consistent with the emission reduction goals . . . including transitioning to clean energy resources and expanding low carbon transportation choice of Oregonians."

[4] SB 1547; https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled
[5] SB 1547 Section 20 (C)(3)
[6] SB 1547 Section 20 (C)(2)(b-c)
[7] SB 1547 Section 20 (C)(2)(e)
[8] EO 20-04: https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf

In support of these goals, PGE embraces our role as a key partner in our customers' transition to electricity as a transportation fuel. By maximizing benefits and minimizing costs, electric transportation has the potential to provide benefits to all our customers. We envision a future where the grid and transportation sectors work together harmoniously to create value for our communities through cleaner air, lower costs, increased renewable penetration, and enhanced reliability.

Q. Please provide a brief summary of the TE program.

A. In response to SB 1547 and Commission Order No. 18-054, PGE implemented three pilots to support the build out of public charging infrastructure, electric mass transit, and outreach/technical assistance. In addition, PGE filed a Transportation Electrification Plan[9] and proposed several new initiatives. PGE's Plan describes three priority areas where we will focus our efforts:

1. Charging Adequacy – ensuring customers have access to reliable charging infrastructure where and when they need it
   a. 2025 Goal: 5,000 EV charging ports.
   b. Key initiatives: Retail Electric Vehicle Charging (Schedule 50, Advice No. 21-06), Nonresidential Electric Vehicle Charging Rebate Pilot (Schedule 52, Advice No. 20-19 and Advice No. 21-15) Fleet Electrification Make Ready Pilot (Schedule 56, Advice No. 21-09), Pole Charging (Schedule 16, Advice No. 21-02).
2. Fleet Interconnection – enable seamless interconnection (fast, affordable, easy) of fleet vehicles into our system

[9] UM 2033 Transportation Electrification Plan, https://edocs.puc.state.or.us/efdocs/HAA/haa102039.pdf

a. 2025 Goal: 10,000 EV fleet vehicles; 90%+ customer satisfaction score.

b. Key initiatives: Technical Assistance Pilot, Fleet Electrification Make Ready Pilot (Schedule 56, Advice No. 21-09), Electric Mass Transit Pilot, Nonresidential Heavy-Duty Electric Vehicle Charging (Schedule 53, Advice No. 21-03).

3. Charging Optimization – reduce the cost to serve EV loads by connecting customers effectively and managing charging loads (controlling bulk and local system operating costs while maintaining reliability)

   a. 2025 Goal: 15 MW of flexible charging load enabled.

   b. Key Initiatives: Residential Smart Charging (Schedule 8, Advice No. 20-18), Testbed vehicle-control demonstration, vehicle-to-grid demonstration, Energy Partner Program (Schedules 25 & 26, Advice Nos. 20-35 and 20-26).

4. We have also established goals to decarbonize PGE's fleet

   a. 2025 Goal: 38% of PGE's fleet electrified (60% by 2030).

   b. Key Initiatives: site planning and make-ready; EV procurement; change management.

Q. Is the TE program the same as the FLP?

A. No. While the FLP addresses TE activity, it only addresses the portion that will have a flexible load component, such as grid-enabled home electric vehicle chargers and flexible load within the built environment and TE infrastructure. More FLP details are included in Section III above and in PGE Exhibit 600.

Q. Are there existing dockets associated with TE?

A. Yes. There are several open dockets related to TE in which PGE is participating:

- UM 1811: PGE's Transportation Electrification Plan;
- UM 1826: PGE's Clean Fuels Program Plan;
- UM 1938: Deferral of PGE's O&M expenses associated with three approved TE pilots – Electric Avenue, TriMet, and Outreach/Education;
- UM 2003: Deferral of O&M expenses associated with residential and business EV charging pilots;
- UM 2033: PGE's Transportation Electrification Plan; and
- UM 2165: Transportation Electrification Investment Framework.

Q. Has the Commission approved any of PGE's TE initiatives?

A. Yes. The Commission has approved several initiatives:

- Electric Avenue Pilot: the build out of 6 public quick charging sites;
- Electric Mass Transit 2.0 Pilot: the deployment of transit charging infrastructure for a single transit electrification project;
- Outreach & Technical Assistance Pilot: customer education, ride and drive events, and technical assistance support for fleet customers;
- Pole Charging demonstration: deployment of charging infrastructure on two distribution poles;
- Residential Smart Charging program: rebates for residential customers installing connected charging stations at their homes and for participating in DR events;
- Business Charging program: rebates for commercial customers installing charging infrastructure;
- Fleet Electrification Make-Ready Pilot: support for fleets by reducing the customer cost and complexity associated with transitioning to electric transportation fuel;

- Nonresidential Heavy Duty Electric Vehicle Charging; and
- PGE has filed our Clean Fuels Program Plan annually and the Commission has accepted our TE Plan.

Q. Does electric transportation create value for utility customers?

A. Yes. TE creates economic benefits for all customers. We estimate that in 2022, passenger EVs will contribute over $11 million[10] in customer value by increasing revenue in excess of the cost of that energy and capacity. The added load will, in turn, put downward pressure on customer prices. We further estimate that passenger EVs can create nearly $1.4 billion in gross benefits for our customers through 2050 and over $450 million in net benefits[11].

In addition, burning gasoline and diesel fuel have significant impacts on our air and water quality, including generating regional haze, lung-affecting particulate matter, heavy metals in the water supply, and cancer-causing substances. These impacts disproportionally affect underserved communities[12]. Electrified transportation significantly reduces local air pollution caused by vehicles, and helps the electricity system integrate renewable energy resources, reducing the cost to decarbonize our electricity supply.

Q. Please explain what TE costs are included in the base prices and what will continue to be recovered through the existing deferrals.

A. Current TE pilot costs that are included in the Docket Nos. UM 1938 and UM 2003 will continue to be deferred. The costs that are included in base prices represent the growth in our TE Portfolio and will support administration of Fleet Charging Services, charging software

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[10] This was estimated by using Tariff Revenues net of energy and capacity cost. This is exclusive of program costs.
[11] Docket No. UM 2033 Section 3.1.2. https://edocs.puc.state.or.us/efdocs/HAA/haa102039.pdf
[12] Air Quality Analysis and Statistics for Portland: https://www.iqair.com/us/usa/oregon/portland

and data services, and equipment maintenance. Table 2 below summarizes accounting for TE activity:

Table 2
TE Accounting Activity

Accounting Mechanism	Costs
Deferral (UM 1938)	O&M costs associated with original UM 1811 pilots (including Electric Avenue Network O&M, Outreach/Technical Assistance, and pilot evaluation)
Deferral (UM 2003)	O&M costs associated with new UM 1811 pilots (including residential smart charging rebates and business charging rebates)
Base prices	Capital expenditures (e.g., Electric Avenue Network, Electric Mass Transit Pilot, Future charging infrastructure, Fleet Charging Services) O&M costs associated with Fleet Charging enablement, and future charging infrastructure (e.g. Outreach, Data Analysis, Program Management, Software licensing fees, non-capitalized engineering-related costs, hardware maintenance) O&M associated with TE Portfolio administration (management, outside services, data)

Q. What is your forecast of 2022 O&M expenses associated with TE and how much is incremental to 2020 actuals?

A. PGE's 2022 forecast for TE is approximately $1.8 million of non-labor expenses and $1.7 million of labor expenses, which are all incremental to 2020 actual costs. Increases in non-labor represent expenses such as planning and design, charging data management and analytics, market studies, program evaluation, and equipment O&M. These resources will be used to support growth in our fleet and mass-market charging offerings.

V. Payment Options

Q. What are the available payment channels that customers can use to pay their utility bills?

A. Currently 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, and over the phone with a PGE Customer Service Advisor. Knowing that flexibility and optionality is important to all our customers, PGE just added the ability to pay through PayPal and Amazon Pay on June 30, 2021 and will be expanding to include Google Pay and Apple Pay in 2022.

Providing payment opportunities like PayPal allows flexibility outside of the confines of traditional banking models, which is supportive of customers who may not have a traditional bank account. Additionally, this provides the ability to do business with us in the way customers choose. 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 these options. All these options are easy and secure and require the ability of the customers to use a debit or a credit card necessitating expanded use of the Fee Free Bank Card.

Q. Please provide a brief summary of the debit and credit card payment options 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.[13] Adoption has steadily increased, and the service currently comprises over 10% of all payments from PGE's residential customers. Approximately 50% of customers using this service, both one-time and recurring, are considered low income.

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 the larger nonresidential customers. Additionally, commercial customer interest in fee free bank cards has increased and makes up the primary source of customer frustrations regarding our electronic payment options.

Q. How does PGE currently treat debit and credit card payments for business customers?

A. Prior to the COVID-19 Pandemic, business customers were assessed a third-party vendor fee if they chose to pay their utility bill with a debit or credit card. To alleviate the financial stress during the COVID-19 recession, PGE notified OPUC Staff and proceeded to temporarily waive the debit and credit card transaction costs for all non-residential customers. Providing this option enables small non-residential customers more flexibility and ease to run their businesses and the feedback from business customers regarding this change has been overwhelmingly positive.

[13] Order No. 14-422 limits the Fee free Bank Card Program to residential customers.

Q. What proportion of card payments come from debit vs. credit cards and what is the fee difference between those cards?

A. Residential customers use credit and debit cards equally at roughly 50% of card payments coming from each card type. When business customers pay with a bank card, roughly 70% of the cards are credit cards and the remaining 30% are debit cards. The fee for use of a bank card is the same regardless of the type of card the customer uses.

Q. Does PGE have a proposal with respect to its debit and credit card payment option?

A. Yes. PGE has two proposals. First, PGE has updated its forecast for the residential card program to accurately reflect the increased use of the program and has included that amount in the rate case. Second, we propose to allow businesses (primarily our Schedule 32 customers) to participate in the fee free bank card option similar to residential customers and include this cost in our 2022 test year forecast.

Q. Please explain why PGE is making this proposal to expand access of fee free card payments to small business customers.

A. Customer expectations of having digital options for payments continue to change for both residential and small commercial customers. Feedback from customers show that customers expect to have the fee free card payment option with any business, utilities included. A peer utility in Oregon has offered fee free debit and credit card processing for both residential and commercial customers since 2012[14] – many business customers are served by both companies but have different payment options. Offering this option will enable a consistent and seamless experience for customers as they transact with both companies. Other utilities that offer the fee free transactions for commercial customers include Avista, Alliant Energy, and Minnesota

[14] NW Natural Gas Company, Docket No. UG 221.

Power,[15] Superior Water, Light & Power Company.[16] It has also become customary for municipalities and governments to allow payments for services with a fee free bank card including agencies such as the Portland Water Bureau as well as Oregon and Washington State Parks.

Q. Why is it important to offer this option?

A. Residential customers continue to express gratitude for the flexibility and prior to March 2020, small business customers continued to ask for the same flexibility. It is important that we continue to offer methods of payment that provide customers options, consistent with what they experience in other areas of their lives and business interactions. These options are staples for how customers expect to do business with any company they encounter, including other peer utilities. The ability to pay with fee free bank cards is mainstream and appropriate to allow for our small business customers now and in the future.

Q. What additional cost have you included in your 2022 forecast based on this proposal?

A. Our 2022 O&M forecast includes the increased adoption costs associated with bill payments made by bank cards (debit or credit) for both residential and small commercial customers. We estimate the incremental cost to be approximately $0.5 million for the increased adoption of the residential program and $1.1 million to expand the program to commercial customers. These increases were determined using the forecasts for 2020 in comparison to actual 2020 expenses, as well as actual adoption in 2021. The forecasts were developed in partnership with our vendor as well as the adoption curves observed at NW Natural and other peer utilities for small commercial customers.

[15] Docket No. E015/GR-16-664
[16] UE-160228, Exhibit SLM-1T

VI. 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 May 1, 2022. 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 FLP, expansion of PGE's TE work and the Fee Free Bank Card Option to residential and small business customers.

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. McFarland please describe your qualifications.

A. I received a Bachelor of Science Degree in Management Information Systems and Accounting from Miami University and a Master of Business Administration from the Northwestern University. I served for eight years in finance and management roles at Procter & Gamble and served as Director, Global Digital Experience & Connected Vehicles at General Motors. I joined PGE in April 2019 as the Vice President and Chief Customer Officer to oversee customer experience and development of new strategies to meet the changing needs of the customer.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Flexible Load Plan

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Jason Salmi Klotz

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I. Introduction and Overview

Q. Please state your name and position with Portland General Electric Company (PGE).

A. My name is Jason Salmi Klotz. I am a Principal Product Development Specialist in PGE's Product Portfolio Management group. I have lead responsibility for PGE's Flexible Load Plan (FLP) submitted to the Public Utility Commission of Oregon (Commission or OPUC) in Docket UM 2141 (UM 2141). My qualifications appear at the end of this testimony.

Q. Please summarize your testimony.

A. In this testimony, I discuss PGE's FLP. More specifically, I explain PGE's proposal for submitting a portfolio-level, multi-year plan, and cost recovery options to address that plan, later this year.

Q. Has the Commission issued any decisions regarding PGE's FLP?

A. Yes. In UM 2141, PGE submitted the FLP, which was recently accepted by Commission Order No. 21-158. In that order, the Staff of the Commission summarized PGE's filing as:

> PGE filed its Flexible Load Plan (FLP or Plan) in compliance with the Commission's acknowledgement of PGE's 2019 IRP. While the FLP is a comprehensive informational filing, it proposes only one action for Commission consideration: to move to portfolio level multiyear planning, budgeting, reporting, and cost recovery for PGE's flexible load activities. If the Commission adopts Staff's recommendation to accept the FLP, PGE will subsequently submit a portfolio-level plan for Commission approval later this year.

Q. What is the definition of flexible load?

A. Flexible load is a dynamic resource typically located at or near a customer site, which can modify load in response to a rate design or a dispatch instruction originating or issued by PGE. One such example is electric vehicle supply equipment, enabled with "smart" technology and located at a multifamily establishment. Flexible load resources are developed in partnership with our customers.

Q. Why is flexible load important?

A. In order to pursue the state's greenhouse gas emissions reduction goals and our system's decarbonization goals, PGE must pursue all possible resource options. Flexible load is a resource which can help balance intermittent renewables and provide resiliency, as well as other system and customer benefits. Customers who participate in flexible load offerings can help lower their overall energy costs while providing valuable system benefits. This same value proposition supports our long-standing energy efficiency (EE) investments.

Q. What is the purpose of the FLP?

A. The purpose of PGE's FLP is to: 1) implement portfolio-level planning that will optimize, leverage, and consolidate PGE's numerous flexible load activities across different customer sectors; and 2) provide the Commission and stakeholders insight into PGE's flexible load planning and development activities inclusive of demand response (DR) activities. This will allow PGE to move from designing and managing measures independent of each other, to coordinating their development to optimize benefits and costs across a portfolio of flexible load resources. In short, PGE proposes to shift to portfolio-level, multi-year planning, budgeting, and reporting for its flexible load resources. PGE's FLP, as submitted and accepted in UM 2141, is provided as PGE Exhibit 601.

Q. How would the FLP interact with or be informed by PGE's Integrated Resource Plan (IRP)?

A. PGE's flexible load acquisition goals are set in the IRP, as determined by a flexible load resource's ability to be the lowest cost, least risk resource. The current flexible load goal was approved in PGE's 2019 IRP (Docket LC 73). In support of these goals, PGE will submit a Flexible Load Multi-Year Plan (Multi-Year Plan) per the Commission's decision in UM 2141.

PGE envisions the Multi-Year Plan to have two phases: Phase I will demonstrate how PGE will acquire flexible load in 2022 and 2023 in pursuit of the 2019 IRP goal of 211 seasonal megawatts (MW), include a budget necessary to support this, and a proposal for cost recovery. This Phase 1, Multi-Year Plan is currently scheduled to be submitted in Q4, 2021. To align PGE's newly developing Distribution System Plan (DSP) with the IRP, PGE envisions Phase II of the Multi-Year Plan to be submitted in late 2022. Phase II of the Multi-Year Plan will establish flexible load targets and budgets to meet goals set in PGE's 2022 IRP's Preferred Portfolio as well as PGE's 2022 DSP. PGE's DSP will create locational forecasting and an action plan for flexible loads. This will inform the Phase II Multi-Year Plan with more granular resource detail than was available during Phase I of the Multi-Year Plan.

Q. What are your current projections for FLP costs?

A. Three components make up our total cost projections for years 2021 and 2022: demonstrations, pilots, and programs. Each of these is offered under an approved Commission tariff and summarized below.

- Demonstrations are currently conducted in the Testbed Pilot (Testbed). Phase I of the Testbed is set to expire at the end of 2021, with annual costs estimated to be approximately $3.2 million. PGE is planning to propose Phase II of the Testbed in August 2021; if approved it is estimated to cost approximately $2.0 million in 2022.
- Pilot work, which presently includes Residential Smart Electric Vehicle Charging and Residential Energy Storage, is estimated to cost approximately $2.9 million in 2021 and $4.9 million in 2022.

- Maturing DR pilots on a pathway to program status (i.e., Flex Peak Time Rebate, Residential Thermostats, Energy Partner and Multifamily Water Heaters) are estimated to cost approximately $13.6 million in 2021 and $14.0 million in 2022.

FLP costs are expected to increase as PGE adds additional products to our portfolio such as single-family water heaters and new construction bundles.

Q. How is the rest of your testimony organized?

A. In the next section, I discuss PGE's current regulatory treatment of flexible load resources and explain why most of those costs are not included in the current general rate case (GRC). I then provide details for alternative cost recovery methods and explain why those alternatives are appropriate given the evolving nature of the flexible load resources. Next, I discuss the potential for including flexible load costs in a future GRC. Finally, I provide concluding remarks to summarize PGE's FLP proposal.

II. Current Regulatory Treatment

Q. Please describe how the Commission currently regulates PGE's flexible load resources.

A. Beginning in 2011, following deployment of PGE's advanced metering infrastructure system, PGE initiated its DR pilots with Energy Partner, which provided an automated DR option for large non-residential customers. Those costs were deferred for separate ratemaking treatment under Docket UM 1514 and approved for cost recovery via PGE Schedule 135. Since then, Energy Partner has evolved into two DR pilots[1] and PGE has implemented the following additional DR pilots, all of which have cost recovery through PGE Schedule 135:

- Energy Partner – Docket UM 1514 – PGE Schedules 25 and 26.
- Direct Load Control Thermostats – Docket UM 1708 – PGE Schedule 5.
- Peak Time Rebate – Docket UM 1708 – PGE Schedule 7.
- Multifamily Residential DR Water Heater – Docket UM 1827 – PGE Schedule 4.
- DR Testbeds – Docket UM 1976 – PGE Schedules 13, 14, and 25.

Q. Are there other flexible load activities which are not represented by the above list?

A. Yes, PGE is conducting a residential energy storage pilot through Schedule 14, Docket UM 2078. Additionally, our residential electric vehicle charging pilot has a DR component. These costs are deferred through Docket UM 2003. In addition, Electric Avenue has demonstrated some flexible load capabilities and DR savings through utilization of a peak pricing surcharge. These costs are deferred through Docket UM 1938. PGE has separately developed and made available a Time-of-Day rate. Within the Testbed, PGE is also conducting collaborative work with the Energy Trust of Oregon on two EE and flexible load

[1] The non-residential direct load control pilot (PGE Schedule 25) and the non-residential DR pilot (PGE Schedule 26).

demonstrations: single-family, DR-enabled water heaters and DR-enabled ductless heat pumps. The Testbed is also conducting work with FleetCarma to test various time of use structures and incentives for electric vehicle charging.

Q. Are these activities included in your total flexible load cost estimate?

A. Yes.

Q. Have you included any of these pilots' costs in this GRC?

A. As discussed in PGE Exhibit 500, PGE shifted the pilots' labor-related costs to base rates because labor is more flexible and can be applied to a variety of DR programs, whereas the non-labor components are dedicated to individual programs and only for specific activities. Non-labor pilot costs, therefore, will continue to be deferred and amortized through supplemental schedules until Commission action on the Multi-Year Plan.

Q. Why are the non-labor costs being deferred and not shifted to base rates?

A. Base rates represent regular, stable, and ongoing costs of doing business. Although base costs are subject to certain variability, they can be forecasted with reasonable accuracy and their variability typically falls within a normal range of business risk. PGE's DR pilots, however, are still in a state of transition. They face considerable uncertainty with respect to costs and customer participation levels, and in some cases completion of testing and deployment of enabling technologies. The pilots are also subject to future evaluations to finalize learnings and to establish the means to achieve overall goals. Even as the pilots transition to programs, they are not immediately mature and stable. Instead, there is a period of significant ramping and growth as the programs experience increases in scale and scope. In short, until the programs become fully mature and stable, they do not represent regular, on-going costs suited for forecasting in base rates but are more appropriate for alternative cost recovery treatment.

Q. If most of the costs are not included in this GRC, why is PGE discussing the FLP in testimony here?

A. In comments provided in UM 2141, the OPUC Staff and other parties did not indicate a preference for PGE shifting its flexible load costs from deferred accounting treatment to base rates at this time, but did express a strong interest in having PGE discuss in the GRC how we plan to move forward with the FLP and Multi-Year Plan. Ultimately, all parties including PGE agree that it is time to move away from deferred accounting.

Q. Why is there a need to move away from deferred accounting?

A. Deferred accounting has been useful and appropriate during the pilots' initial phases when operating parameters and enabling technologies were being tested and evaluated over a series of years. This allowed PGE to accumulate sufficient data and customer survey results to provide meaningful learnings to guide the pilots to cost-effective, scalable operations. As PGE has expanded the number and magnitude of DR pilots, however, the treatment of the pilots as separate deferrals has made it increasingly difficult to identify aggregate rate impacts. Consequently, there is consensus that a more comprehensive approach is needed.

III. Proposal for FLP

Q. Does PGE have a proposal for the FLP and multi-year plan that would replace deferred accounting?

A. Yes. PGE believes there are two similar methods that provide a reasonable alternative to deferred accounting. Both involve cost recovery by means of a supplemental schedule, with or without a balancing account, as described in more detail below. Ultimately, the two methods align with a multi-year plan that would be for a set amount of cost recovery over a specific period of time. As described below, they also allow for a transition from the first alternative to the second alternative if PGE were to continue the FLP through a series of multi-year plans.

A. Supplemental Schedule with Balancing Account

Q. Please describe the first of the two alternative methods.

A. The first alternative would involve cost recovery through use of a supplemental schedule supported by a balancing account mechanism. This alternative recognizes the significant amount of ramping and growth flexible load resources will experience as they expand their scale and scope in transitioning from pilots to programs. This is particularly evident by PGE's 2019 IRP goal of expanding flexible load resources from the current 68 MW to 211 MW by 2025. This alternative would also recognize that some determination remains on the overall efficacy of having certain operations and maintenance activities for flexible load resources being performed by third-party contractors versus internal PGE personnel and systems. To address the significant change that is inherent in this phase of PGE's flexible load development, PGE proposes to establish a mechanism that consists of the following aspects:

- A supplemental schedule to collect a levelized, forecasted plan amount over two years. The supplemental schedule can remain fixed over the period or allow the flexibility of updates, if appropriate, to account for changes in programs, scale or scope, and/or goals.
- A balancing account to track the flow of costs and tariff collections. This would allow the matching of revenues and costs over time so that intertemporal cost fluctuations would not impact PGE's operating results in a given year.

B. Supplemental Schedule without a Balancing Account

Q. Please describe the second of the two alternative methods.

A. The second alternative would also involve cost recovery through use of a supplemental schedule but not one supported by a balancing account mechanism. This alternative recognizes the continued transition from evolving programs to mature programs and the remaining growth the flexible load resources will experience as their final scale and scope are being identified and achieved. To address the level of change inherent in the latter phase of flexible load development, PGE proposes the establishment of a mechanism that consists of the following aspects:

- A supplemental schedule to collect a levelized, forecasted plan amount over two years. The supplemental schedule can remain fixed over the period or allow the flexibility of updates, if appropriate, to account for changes in programs, scale or scope, and/or goals.
- No balancing account to track the flow of costs and tariff collections. This means all FLP costs and revenues will flow to PGE's income statement and that PGE

would bear the forecast risk of annual costs against revenue (i.e., intertemporal cost fluctuations would impact PGE's operating results).

C. Additional Considerations

Q. Please explain how either of the two methods described above would address situations where PGE either underspends or overspends the established plan amount in conjunction with either under- or over-achievement of plan goals.

A. I envision that the Multi-Year Plan will entail a maximum amount of cost recovery for the supplemental schedule to collect over the specified period. Because the proposed supplemental schedules would not involve an automatic true-up to actual costs, as occurs with the current deferrals, PGE also proposes the following treatment:

- If PGE incurs more cost than the forecasted maximum amount of cost recovery, and if PGE does not achieve flexible load capacity greater than the established goal, then PGE will absorb the excess costs.
- If PGE incurs more cost than the forecasted maximum amount of cost recovery, and if PGE achieves flexible load capacity greater than the established goal, then: 1) customers will absorb the excess costs in proportion to the amount of excess capacity compared to forecasted capacity; and 2) PGE will absorb any additional costs above the customers' share.
- If PGE incurs less cost than the forecasted maximum amount of cost recovery, and if PGE does not achieve the flexible load capacity goal, then PGE will refund the underspend costs to customers.
- If PGE incurs less cost than the forecasted maximum amount of cost recovery, and if PGE does achieve or exceeded the flexible load capacity goal, then PGE and

customers will share the underspent costs on a 90/10 basis, with customers being refunded 90% of the underspent costs and PGE retaining 10%.

- Finally, during the preparation of test year forecasts for general rate cases, PGE will fully separate multi-year plan costs from base costs so as not to double collect them.

IV. Regulatory Alignment Mechanisms

Q. Do you foresee a possible move of FLP costs to base rates?

A. Yes. After flexible load programs become mature and stable, PGE agrees that they could be suited for incorporation into base rates. There are two considerations associated with this eventual outcome, however, that would need to be addressed. The first is whether OPUC Staff and parties prefer to have flexible load costs embedded in base rates or continue to be separated by means of a supplemental schedule. This consideration relates to the nature of base rates that entails:

- All cost and recovery determinations are tied to rate case filings.
- There is no potential for annual updates of FLP costs to account for changes in programs, scale or scope, and/or goals between rate cases.
- FLP costs would be determined as part of all other costs in base rates.
- Actual FLP costs would be subject to similar managerial pressures as other base costs.
- PGE will bear the forecast risk of annual costs against revenue.

In summary, the decision to move FLP costs to base rates will be based on: 1) the degree of transparency desired between base rates and a supplemental schedule; and 2) the extent to which flexible load will consist of elements that are more suited to separate rate treatment versus base rates. In other words, assuming the persistence of rapidly emerging technologies and changing customer preferences, a portion of flexible load will continue to involve demonstration projects and pilots with considerable degrees of uncertainty and changing costs.

Q. What is the second consideration that you wish to address regarding an FLP transition to base rates?

A. The second consideration relates to the matching of risks and benefits associated with the FLP. Although mature, stable flexible load programs appear suited to base rate recovery, they would still be subject to considerable forecast risk as technologies evolve and customer preferences change in between rate cases. In addition, PGE believes there should be the recognition that flexible load replaces supply-side resources for which PGE earns a return on those owned as rate base. In summary, I propose that flexible load resources, as eventually included in base rates, provide PGE with earnings potential.

Q. How would this earnings potential be achieved?

A. There are two ways this could be accomplished. The first is more complex but has precedent in prior rate making. With this method, PGE's flexible load costs would be applied to an asset account rather than expense, and that account's balance would be included in rate base for which it would earn PGE's authorized weighted average cost of capital similar to all other rate base. This asset would then be amortized over a period of years, with the amortization cost representing the "return of" component of rate making.

Q. What is the precedent for this method.

A. In the 1990s, utilities in Oregon were incented to invest in EE and were allowed to incorporate those costs in rate base for "return on" as part of the Commission-approved "SAVE" program. That program ended with the establishment of the Energy Trust of Oregon and the Public Purpose Charge.

Q. What is the less complex method to achieve earnings potential for the FLP?

A. This method is simply a cost-plus-fee approach where a return percentage is applied to the FLP cost forecast and the total cost-plus-fee amount is incorporated into rates. In reality, this approach could be equally applied to the supplemental schedule method, as discussed in

Section III, if the Commission were to agree that: 1) the supplemental schedule method remains preferrable to base rate recovery; and 2) the fee adder represents a reasonable benefit and incentive for PGE.

Q. Are there other earnings mechanisms PGE is exploring to align customer investment in flexible load, state policy and utility investment?

A. Yes, there are several that PGE has been following that will inform a future proposal to the Commission.

Q. Please provide an informative example.

A. Consolidated Edison (ConEd) in New York worked with their Commission, stakeholders and the community to develop a performance incentive mechanism that aligned with the communities' interest in local investment, grid planning's desire to address a local load pocket, and the ability of the utility to attract investment. The project known as the Brooklyn Queens Demand Management Program,[2] a non-wires alternative, deferred an investment of $1 billion into a seven-year project at roughly half the costs. The program included direct install, multi-family efficiency, flexible load auction mechanism, partnership with the New York City Housing Authority, distributed generation, and voltage optimization. The New York Public Service Commission (NYPSC) adopted an incentive mechanism which included an authorized rate of return on program costs and the potential for ConEd to receive up to 100 basis points in performance incentives above their authorized rate of return. In addition, 45 basis points of return were tied to achieving the proposed demand reductions, 25 basis points were tied to increasing diversity of DER in the marketplace, and 30 basis points were

[2] https://www.coned.com/en/business-partners/business-opportunities/brooklyn-queens-demand-management-demand-response-program; https://breakingenergy.com/2014/12/22/ny-psc-approves-con-edison-bqdm-program/

tied to achieving a lower $/MW value than traditional investment solutions. The project came in part to be known as the REV Test Bed,[3] where ConEd also issued a Request for Information for local contractor work and conducted local customer outreach. In 2017, ConEd stated the net present value of the project to be $94.9 million including $65.5 million of benefits from delaying load transfers, $549 million of benefits from delaying substation/transmission investments, and $133 million in benefits from avoided capacity, energy, distribution, environmental, and line losses. The NYPSC has extended the project from its initial 3-year scope to having no termination date. The total benefits of the project were $747.8 million against $652.9 million in costs.

Q. Are there Northwest examples that are informing PGE's perspective and possible proposal?

A. Yes, in 2019 the Washington Legislature passed Senate Bill 51116, the Clean Energy Transformation Act, which authorized a rate of return on utility power purchase agreements and distributed energy resource investments including DR. Additionally, in their 2018 GRC, Northwestern Energy proposed a rate of return on all demand side management (DSM) investment. The proposal, which ultimately was not approved, had the support of the Northwest Energy Coalition and the Sierra Club. In 2004, Nevada become the first state to permit utilities to earn a bonus rate of return on DR and EE investment, which become regulatory assets that are eligible to earn a return of up to 5% more than traditional supply-side investments on the equity portion of the authorized return. We know of seven other states (i.e., North Carolina, Hawaii, Michigan, Texas, Vermont, Rhode Island, and Massachusetts) where the utility received an earning mechanism for DSM investments.

[3] REV is the acronym used for Reforming the Energy Vision effort in New York state.

Q. What are the anticipated next steps for PGE on the issue of regulatory alignment?

A. As stated in chapter 5 of the FLP, PGE is making investments to acquire and develop flexible load. PGE's investment supports our work to provide customers with energy solutions, which can help lower bills, support communities, and decarbonize the grid. PGE showed in its Exploring Pathways to Deep Decarbonization[4] study that we will need hundreds of MW of flexible load and distributed energy resource development to meet Oregon's greenhouse gas reduction goals. Aligning investment and earnings opportunities can help the PGE system, its customers, and the state reach those goals by attracting investment. To meet these aggressive targets, it is our intention to propose an adjustment mechanism either via the Multi-Year Plan process or the Distribution System Plan process, where appropriate stakeholder engagement can occur.

[4] See PGE Exhibit 602, Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory.

V. Conclusion

Q. Please summarize your proposal regarding the FLP.

A. Except for certain labor costs discussed in PGE Exhibit 500, we have not included flexible load costs in the current GRC. Instead, we intend to issue a portfolio-level, multi-year plan and budget in October 2021 in UM 2141, and propose that the Commission approve the transition of FLP cost recovery from current schedules to a multi-year plan, as discussed in Section III, above. We will also propose in a future GRC, flexible load costs be considered for continued use of a supplemental schedule and/or base rates and that return-on potential be applied to those costs.

VI. Qualifications

Q. Mr. Salmi Klotz, please describe your qualifications.

A. I have 17 years of experience in the industry having worked for the Vermont Public Service Commission, the Federal Energy Regulatory Commission, the California Public Utility Commission, Bonneville Power Administration, the Northwest Energy Efficiency Alliance, the OPUC and PGE. My career has mostly focused on the role of DSM, smart grid technologies and their ability to affect retail and wholesale market functions. I hold a Bachelor of Arts in English and Philosophy from the University of Montana Missoula, a Master of Environmental Policy and Law, and a Juris Doctorate from Vermont Law School. I am a member of the Oregon State Bar. For the last six years I have also been teaching Energy Policy and Law at the University of Oregon School of Law.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
601	UM 2141 Flexible Load Plan
602	Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory

Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

December 24, 2020

Via Electronic Filing

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

Re: UM 2141 Portland General Electric Company Flexible Load Plan

Dear Filing Center:

Attached for filing is Portland General Electric Company's (PGE) Flexible Load Plan, docketed as UM 2141. PGE identified a missing footnote, number 85, and this errata filing contains that footnote.

Thank you,

/s/ Karla Wenzel

Karla Wenzel
Manager, Regulatory Policy & Strategy

Enclosure

PGE's Flexible Load Plan

December 2020

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Flexible Load Plan Road Map

The Flexible Load Plan has four parts. Chapter 1 is a review of current activity. Within Chapter 2 the reader will find a proposal focused on operations, funding, goal setting and practices. PGE's proposal in Chapter 2, requests acceptance of a practice entailing multiyear planning and budgeting, yearly updates and quarterly reporting. Costs would be recovered through Schedule 135[1] similar in nature to energy efficiency planning, budgeting and cost recovery through Schedule 109[2].

The following provides a roadmap through the Flexible Load Plan:

- Chapter 1 is a review of current activity with a brief description of the pilot or program activity. A more comprehensive review of each pilot or program activity can be found in the Appendix, including but not limited to discussion regarding the pilot or program goals, market potential, lesson learned, management of costs and cost effectiveness, evaluation, and moving the activity from pilot to program

- Chapter 2 is a review of current planning practices, goal setting, and regulatory treatment. The section goes on to propose a treatment of flexible load similar to energy efficiency, where PGE will adopt many of the planning, development, budgeting best practices in place in Oregon and the region. PGE proposes to have flexible load treated on a portfolio basis over a course of years with a multiyear budget updated annually and aligned with a multiyear flexible load plan. Additionally, PGE proposes a funding mechanism similar to how energy efficiency is funded. This will give the Commission and stakeholders the necessary level of transparency and oversight.

- Chapter 4 is a review of how PGE assesses cost effectiveness. Here PGE responds to Commission Staff's requests, found in Docket LC 73, for valuation changes to PGE cost effectiveness methodology.

- Chapter 5 attempts to open a discussion on regulatory alignment of the resource, such that customer, stakeholder, and shareholder interests are aligned around the procurement of flexible load as we decarbonize our system at the greatest benefit and at least cost to our customers.

- Within the Appendix the reader will find detail on each of our programs including cost benefit tables and scoring. Additionally, we have included a table of expenditures and forecasted budgets. These tables also include a transparent look at our progress to

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[1] Schedule 135 is PGE's cost recovery tariff for demand response pilot costs that are not already recovered in rates. https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_135.pdf

[2] Schedule 109 is PGE's tariff to collect costs from customers for SB 838 energy efficiency activity. https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_109.pdf

acquire capacity to meet our 2016 IRP savings goals. Lastly, the Appendix includes a user adjustable cost benefit spreadsheet provided in response to Commission Staff's comments in LC 73 whereby Staff requested PGE consider several adjustments to cost effectiveness.

Flexible Load Plan Executive Summary

Purpose of the Flexible Load Plan

The purpose of the Flexible Load Plan is multi-part:

1. The Flexible Load Plan attempts to demonstrate the evaluation of demand side resource development at Portland General Electric (PGE) within the context of other jurisdictional activities, policy changes within Oregon, at the regional and federal level and PGE's future resource needs informed by our decarbonization strategy.

2. To show maturity of program and resource development and propose a change in practice which will give Commission transparency, comprehensive review and regular reporting of PGE's flexible load resource build activity. This sole proposal for Commission acknowledgment is informed by similar best practice in the region where entities are attempting to build demand side management resources.[3]

3. Demonstrate to the Commission and Stakeholders how PGE will conduct flexible resource development through a measure development structure: PGE uses small, discretely targeted activity through demonstration projects to inform pilot activity; promising measures will be taken to scale, which will evolve to programs that are dispatchable by our power operations team. Show how PGE currently leverages the Smart Grid Testbed as a key part of this evolution and commitment to transparency.

4. Transparently communicate our current cost effectiveness methodology and practice and to further show how this practice will evolve with identification of energy values that flexible load is anticipated to provide to PGE's system.

5. Lend insight into how our Integrated Resource Plan and for the forthcoming Distribution System Plan practices model and identify the value of flexible load.

6. Communicate to the Commission, stakeholders and customers our commitment to the development of customer-sited resource development through customer-centric development practices

[3] As there is no written standard for the Commission's review of this Flexible Load Plan, PGE prefers the Commission to acknowledge the Plan but understands that acceptance of the Plan is also an option.

7. Communicate to the Commission, stakeholders and policy makers that PGE is open and ready to discuss regulatory alignment to best situate the company to accelerate investment in flexible load and similar distributed energy resources.

8. Comprehensive and transparently share with all interested parties PGE program activity, costs and savings.

Summary of the Request for Commission Acknowledgement

Though the Flexible Load Plan is extensive, as it is an attempt to transparently and comprehensively review PGE's flexible load activity, it includes only one proposal for Commission acknowledgement. That proposal is a request to move from the current disjointed approach involving multiple deferrals, timelines, and reporting to a comprehensive, multi-part measure development, portfolio level planning, and budget practice similar to best practices employed throughout the region. The detail of this proposal is in Chapter 2.

Relationship to IRP, DSP, Transportation Electrification Plan, and Smart Grid Report

The Flexible Load Plan is focused on flexible load. It is not meant to replace any part of the IRP, the forthcoming DSP, the Transportation Electrification Plan, or the Smart Grid Report. The Flexible Load Plan attempts to show the relationship of flexible load and our flexible load resource build activity in the context of present and planned activity. For example, while the Flexible Load Plan addresses transportation electrification activity, it only addresses the portion that will have a flexible load component, such as grid-enabled home electric vehicle chargers. This measure was identified in our Demand Response Potential Study, found in PGE's 2019 Integrated Resource Plan. Though the Flexible Load Plan discusses these measures, it is not meant to replace the requirements or the planned activity set out in the IRP or PGE Transportation Electrification Plan. Furthermore, the Flexible Load Plan discusses distribution system and resource planning (DSP and DRP, respectively) only to show how PGE envisions flexible load as an important element of DSP modeling, planning processes, and practices. Discussion of DSP within the Flexible Load Plan is not an attempt to influence or preempt an aspect of the Commission UM 2005 Distribution System Planning proceeding. PGE recognizes DSP as a separate planning process.

Summary of Program Evolution from Demonstration, Pilot to Program

At the heart of the Flexible Load Plan is a review of our evolved measure development practices. This process has a three-part structure: demonstrations, pilots, and programs. The process is governed by a Product Lifecycle Management (PLM) stage-gated development process. The structure leverages the Testbed to accelerate development in two significant aspects. First, it utilizes the current investment and high levels of customer engagement to operate small demonstration projects that will inform pilot development on matters of technology viability, energy service values, and planning values. Second, this measure development framework leverages the Testbed's accelerated grid state, where grid system operations and investments have been made in synergy with DER development, customer engagement, and education. These unique characteristics of the Testbed allow PGE to identify and learn from a more advanced state of the grid, thus informing broader grid development activities throughout the organization, including measure development itself.

The following Figure is a synopsis of our measure development process. Further detail can be found in Chapter 2 of this document.

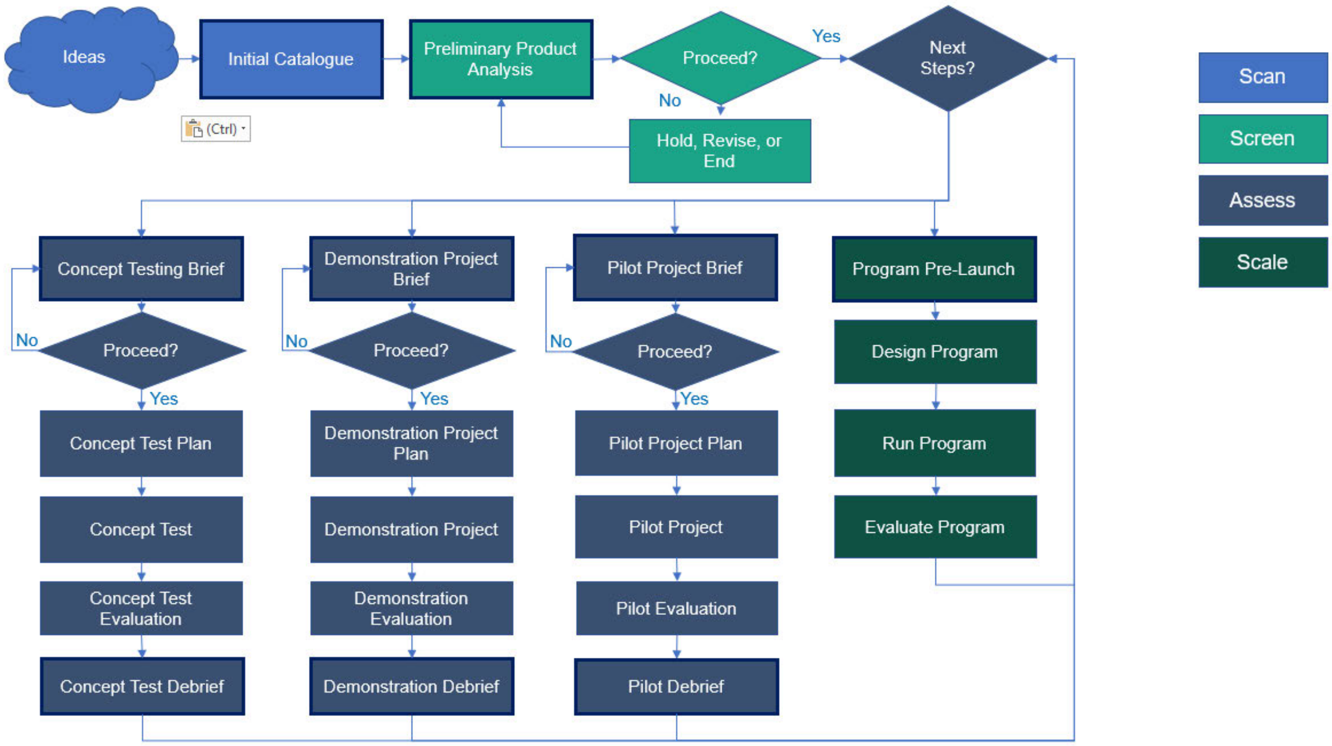

Figure 1 – PGE's Measure Development Process

Purposed Next Steps – Multiyear Operations Plan and Budget

Through this Flexible Load Plan, PGE requests that the Commission acknowledge our proposal to move from the current measure by measure, pilot to program practice accompanied by requests for deferred accounting and later ratemaking, to a more holistic portfolio development process with multiyear plans, budgets, cost recovery, and regular reporting. The Flexible Load Plan contemplates, if acknowledged, a follow-up filing in which PGE would communicate its multiyear flexible load development plans, the associated multiyear budget, and cost recovery.

Chapter 1 Introduction

Chapter Summary

Chapter 1 does not request any action from the Commission. Rather, it communicates the need for a Flexible Load Plan, lays out a history of demand response, and the rationale for why PGE has begun using the term, flexible load. Table 1 in this chapter ties flexible load to grid services, as defined and outlined by the Commission in Docket UM 1751. (Chapter 4 of the Flexible Load Plan reviews these UM 1751 storage use cases and applies them directly to flexible load.) Chapter 1 also raises the concept of a virtual power plant, comprised of multiple flexible load measures, which in aggregate, supply grid services visible to and dispatchable by PGE Power Operations. Chapter 1 then gives a high-level review of planning practices, and finally reviews measure activity, costs, cost effectiveness, and savings. Pilot and program detail can be found in the Appendix of the Flexible Load Plan. Chapter 1 is meant to prepare the reader with necessary information to make the most of the subsequent chapters.

1.1 Purpose of the Flexible Load Plan

The purpose of the Flexible Load Plan is to present a transparent and comprehensive report of current activity that PGE is undertaking to meet our demand response targets set forth in PGE's Integrated Resource Plan (IRP). Additionally, the Flexible Load Plan is meant to communicate and demonstrate PGE's evolving vision of the DR resource such that a greater number of grid services and hours of operation can be obtained. This folds the concept of demand response into a broader category recognized nationally as load flexibility or flexible load. The more expansive concept of flexible load allows for the aggregation of multiple types of behind-the-meter technologies into "Virtual Power Plants." These Virtual Power Plants will lend services to the distribution grid below the substation and the bulk system, when possible, above the substation. The Flexible Load Plan also documents PGE's current practices, openly communicates challenges and constraints, and articulates PGE's understanding of the current limitations of flexible load. The Flexible Load Plan offers a proposal for a new structure for the Public Utility Commission of Oregon (OPUC or Commission) to consider regarding flexible load planning, budgeting, cost recovery, and development.

The Flexible Load Plan also transparently communicates present cost effectiveness practices and PGE's envisioned activity to address the full valuation of flexible load. Flexible load is a new resource to PGE, our customers, and our regulators; PGE is still exploring its capabilities and their associated value. PGE continues to measure cost effectiveness according to the PUC's methodology in Docket UM 1708[4]. PGE is open to applying alternative cost effectiveness frameworks, including the methodology proposed by Staff in Docket LC 73 and forthcoming

[4] Commission Order 15-203, UM 1708, PGE Compliance Filing April 28, 2016, "A proposed Cost Effectiveness Approach for Demand Response."

methodology from The National Efficiency Screening Project (NESP).[5] While there are merits and drawbacks to each of these approaches, PGE hopes that by comparing these methodologies, we can engage stakeholders in an open dialogue regarding cost effectiveness practices.

PGE views the connection to the customer as the most important and valuable connection the company will make. To this end, PGE is seeking to meet customers' needs through the development of new energy solutions. As PGE wants to help customers manage their total energy costs, flexible load programs can help customers lower their bills and better understand how their actions can affect system costs and drive decarbonization. PGE plans and actively manages customer price impacts, recognizing that increased costs affect our relationship with customers.

1.2 History of Demand Response

1.2.1 Early Program History:

Since the 1970s, DR programs have successfully managed load balance during times of grid stress and high-power prices. Detroit Edison was the first utility to implement a load control program in 1968[6]. Similarly, Florida Power and Light deployed a measure with electric water heaters in the 1980s and has since expanded the program to cover central heating and cooling, as well as pool pumps.[7] This program remains one of the longest-running DR programs in the country.

The first DR program in the Northwest was launched after the passage of the 1980 Northwest Power Act (Power Act)[8], with its emphasis on demand-side measures. Established in 1985, the City of Milton-Freewater's program utilized timers to control water heater load[9]. In 2014, the program was updated and expanded to include heating and air conditioning load as part of the NW Smart Grid Demonstration Project[10]. Additionally, large industrial customers[11] taking direct service from the Bonneville Power Administration (BPA) were required to make 25% of their load interruptible as a condition of service. During the 2001 Western Energy Crisis (Energy Crisis), this

[5] The National Efficiency Screening Project mission is to improve cost-effectiveness screening practices for distributed energy resources. NESP is set to release a new cost effectiveness national standard practice manual later this summer. https://nationalefficiencyscreening.org/wp-content/uploads/2019/06/NSPM-for-DERs.pdf.

[6] EPRI, The Demand-Side Management Information Directory, EPRI EM-4326, 1985.

[7] Residential On Call ™ Program. *Available at*: https://www.fpl.com/save/programs/on-call.html

[8] Pacific Northwest Electric Power Planning and Conservation Action 16 USC Chapter 12H (1994 & Supp. I 1995) Act of Dec. 5, 19080, 94 Stat. 2697.

[9] Milton-Freewater's original demand response program used a radio energy management system to send a radio signal to the units to cycle off connected loads, reducing energy when the peak demand set-point was reached.

[10] Of note, when the utility began to replace the old units with the newer models, many customers did not know the units existed. This indicates that certain DR programs can operate without significant disruption while creating efficiencies for utilities and customers. Bonneville Power Administration "*Milton-Freewater: A frontier for new technology.*" September 5, 2014*. Available at*: https://www.bpa.gov/news/newsroom/Pages/Milton-Freewater-A-frontier-for-new-technology.aspx

[11] These customers included aluminum smelter and pulp and paper. The aluminum smelters would rotate which plants would provide the required demand reductions every two weeks.

became the Demand Buy-Back program, and proved successful in lowering demand during times of extreme stress and high prices. Pacific Gas and Electric (PG&E) ran a similar program from 2000-2014 for large customers[12].

In the 1990s, California utilities created a program called the Base Interruptible Program[13]. In exchange for a reduced rate, the utility had the right to call on participants (large business customers) to lower their demand by a specific, contracted amount during emergencies. The program was rarely, if ever, called upon prior to the Energy Crisis, during which it provided over 1,200 MW of DR in the PG&E service territory and was instrumental to managing demand. More recently, the program has been adapted to integrate with the California Independent System Operator (CAISO) and is called upon when the CAISO is in emergency conditions[14].

1.2.2 Post Energy Crisis Advancements

The success of DR in responding to the Energy Crisis led to a renewed national focus on advancing DR as a resource. In the Energy Policy Act of 2005[15] (EPACT '05) Congress required a series of actions by the Federal Energy Regulatory Commission (FERC) with regards to DR and encouraged states to look into the benefits of DR and Advanced Metering Infrastructure (AMI). EPACT '05 offered states federal assistance for "technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in demand response programs[16]". Specifically, EPACT '05 required the FERC to provide technical assistance to the states, and to publish an annual report on progress of the DR and advanced metering development[17]. The *Demand Response and Advanced Metering Assessment* continues to be issued annually and catalogues national DR and advanced metering activity, consumer access to DR programs, regulatory activities, ongoing barriers to DR participation, and DR potential[18].

In 2008, the FERC also issued the first in a series of rulemakings on DR, Order No. 719: *Wholesale Competition in Regions with Organized Electric Markets*, which required that organized markets (ISO/RTO) offer opportunities for DR resources to participate on a comparable basis with generation and eliminated certain barriers to DR participation. In 2011, the FERC issued Order No. 745: *Demand Response Compensation in Organized Wholesale Energy Markets*[19], which

[12] This program originated as E-16 Tariff in Advice No. 00-03, Effective 07/01/00, and was modified.
[13] Pacific Gas and Electric. "*Base Interruptible Program*." *Available At:* https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/demand-response-programs/base-inerruptible/base-inerruptible.page
[14] Pacific Gas and Electric. "*Base Interruptible Program*." *Available At:* https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/demand-response-programs/base-inerruptible/base-inerruptible.page
[15] 42 USC 15801
[16] 16 USC 2642(a)(5)
[17] 16 USC 2642 (e) (1-3).
[18] 2007 -2019 Reports Available at https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp
[19] Order No. 745 also challenged traditional notions of State vs. Federal jurisdiction and was soon addressed by the U.S. Supreme Court in *Federal Energy Regulatory Commission v. Electric Power*

required ISO/RTO markets to compensate DR resources at the full locational marginal price (LMP).

In 2007, the OPUC responded to EPACT '05 when the Commission required that utility IRPs include assessments of "all known resources," including DR, to meet system planning and load requirements[20].

In 2016, the Oregon legislature passed Senate Bill 1547[21] (SB 1547) which established Energy Efficiency (EE) and DR at the top of the loading order[22] for Oregon utilities. In reference to DR, Section 19 of SB 1547 states, "[d]emand response resources result in more efficient use of existing resources and reduce the need for procuring new power generating resources, which, in turn, reduces energy bills, protects the public health and safety and improves environmental benefits". SB 1547 also enables the OPUC to direct utilities to "plan for and pursue the acquisition of cost-effective demand response resources"[23].

1.2.3 Definition of Demand Response

PGE uses the Northwest Power and Conservation Council's (NWPCC) definition of DR as

> *a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/transmission system operator. This change is driven by*

Supply Association et al (EPSA). Justice Kagan issued the majority decision in the case noting that DR, though a resource developed on the retail part of the electric system has direct effects on the wholesale energy system, is a viable and important resource to control energy costs and the FERC does have the authority to require its jurisdictional entities to create pathways for market entrance of DR.

[20] UM 1331, Order Number 07-449, at p. 2 (November 2007) "all known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power . . . and demand-side options which focus on conservation and demand response."

[21] Senate Bill 1547 78th Oregon Legislative Assembly (2016).

[22] Loading Order sets a priority list for electricity sources. The concept of a "Loading Order" was first introduced in The Northwest Power Act (Public Law 96-501) with creation of an obligation by BPA to acquire all cost-effective conservation (EE) prior to purchasing any new resource. The Northwest Power Act was nationally influential as it was the first instance that created a planning obligation to treat a demand-side resource on par with a generation resource. Since the Northwest Power Act's passage, the treatment of EE on an equivalent basis with generation has become standard practice in utility planning.

The Northwest Power Act also directly influenced the development of the Loading Order rulemakings in California. In 2003 the California Energy Commission (CEC) issued a Staff Report entitled, *2003 Integrated Energy Policy Report,* followed three years later by a similar report entitled *Implementing California's Loading Order for Electricity Resources.*[22] Through these two documents, the CEC first established the need to create a system loading order for resource and fuel diversity and then affirmed that utilities have the obligation to first seek acquisitions of EE and DR before any other generating resources. The loading order adopted by the Oregon Legislature in SB 1547 mirrors the language adopted by the CEC.

[23] Senate Bill 1547 78th Oregon Legislative Assembly (2016), Section 19, Codified as ORS Chapter 757.054

an agreement, potentially financial, or tariff between two or more participating parties.

PGE interprets this definition broadly to include a series of grid services offered by the customers to the utility or grid. DR is a category of services ranging from intra-hour services to behavior-based reductions or shifts in energy demand. To create a better categorization of customer-sited energy resources, PGE is looking to shift our language from DR to flexible load. PGE's shift is not new or novel; the industry as a whole has been evolving toward flexible load for several years. Additionally, PGE's working definition of flexible load is consistent with the NWPCC's working definition of DR as several different types of customer-sited technologies can offer the services embedded within the NWPCC's definition. Further, the use of the term Flexible Load is in harmony with Lawrence Berkley National Lab's definition of Demand Flexibility - "the capability of distributed energy resources DERs to adjust a building's load profile across different timescales"[24]. Here the authors, Tom Eckman and Lisa Schwartz, state that there are many economic values of demand flexibility for utility systems. The value of a single "unit" (e.g., kW, kWh) of grid service provided by demand flexibility is a function of the:

- Timing of the impact (temporal load profile)
- Location in the interconnected grid
- Grid services provided
- Expected service life (persistence) of the impact
- Avoided cost of the least-expensive resource alternative that provides comparable grid service[25].

1.2.3.1 Making the Case for Flexible Load

Flexible load is a cornerstone of PGE's commitment to decarbonization while maintaining reliability and affordability. Because flexible load can provide a range of essential grid services, it can help PGE meet the challenges of supporting a future where variable renewable resources provide the bulk of the energy supply. Additionally, if designed with the customer in mind, flexible load programs can address issues of equity and environmental justice.

In April of 2018 PGE issued *Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory*, our "Decarb Study[26]", which explored technology pathways to

[24] Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings, April 202, SEEAction, Tom Eckman & Lisa Schwartz. Available at https://emp.lbl.gov/publications/determining-utility-system-value.
[25] Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings, April 202, SEEAction, Tom Eckman & Lisa Schwartz. Available at https://emp.lbl.gov/publications/determining-utility-system-value.
[26] Gabe Kwok and Ben Haley "*Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory*" Portland General Electric, April 24, 2018. *Available a*t:

achieving an 80% reduction in greenhouse gases (GHGs) across the economy in our service area. The study focused on three bookend scenarios:

- a "High Electrification" pathway relying on electrifying space and water heating in buildings and deploying bulk energy storage to balance high levels of renewable generation;
- a "Low Electrification" pathway including a variety of renewable fuels, electrolysis, and power-gas facilities; and
- a "High Distributed Energy Resource" (DER) pathway, which is highly electrified and distributed, with increased rooftop solar PV and distributed energy storage in buildings and industry. Each of these pathways included high levels of battery electric vehicles (EVs).

Electrification of passenger transportation is a critical component of decarbonization. Within each of the three pathways, passenger vehicles are at least 90% electric by 2050[27]. Charging off peak and as when renewable generation is high or during the middle of the night, and actively managing EV load can mitigate peak load impacts while ensuring that passengers complete all of their intended trips.

Additionally, the Decarb Study found that by 2050, 90% of the generation mix must be carbon free in order to meet the established emissions reduction target. The total quantity of electricity produced must also be increased due to electrification of end-use demand such as heating, cooling, water heating and transportation. However, balancing electricity supply and demand becomes more challenging when variable renewable energy resources are the principal source of electricity supply, as these variable renewable resources have a fuel source, such as wind or solar irradiance, that cannot be stored or controlled.

The supply of energy must be balanced with the demand for energy in real time, down to the second. Today, PGE relies largely on a mix of thermal and hydro resources to provide the grid services that are needed to meet moment-to-moment changes in generation and load. This balance becomes more challenging as more variable renewable resources are added to the system. For example, the Decarb Study shows that renewable generation exceeds load in approximately half of all hours in 2050. To help balance the system, the scenarios in the Decarb Study included expansive customer participation in flexible load programs. Across all scenarios, by 2050, 75% of light duty vehicles and water heaters as well as 50% of space heating and conditioning and clothes washing and drying were assumed to be enrolled in a flexible load program. One key finding of the Decarb Study was that customer adoption of technologies that

https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/exploring-pathways-to-deep-decarbonization-pge-service-territory.pdf?la=en.

[27] Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory, at p.6, Portland General Electric, April 24, 2018. Available at https://www.google.com/search?q=Exploring+Pathways+to+Deep+Decarbonization+for+the+Portland+General+Electric+Service+Territory&sourceid=ie7&rls=com.microsoft:en-US:IE-SearchBox&ie=&oe=&safe=strict&gws_rd=ssl#

were critical to decarbonization, including electric vehicles and heat pumps, also created new and important opportunities for grid balancing via load flexibility. In fact, flexible load programs in the High Electrification scenario grew to about 2,000 MW by 2050, helping to reduce the need for new dispatchable generation resources. While the role of flexible load becomes especially critical in the context of deep decarbonization, these programs can also bring value to customers today. Chapter 4 describes each of the grid services that flexible load can provide and offers insight into the value of providing these services.

PGE also believes that deployment of flexible load solutions can help address environmental justice and equity challenges. Flexible load programs, by their nature, are accessible to all PGE customers regardless of socioeconomic demographics. Yet, without intentional efforts to build equity into our development and deployment of flexible load solutions, systemic energy inequities will persist, including a high energy burden for low-income customers.

To better understand how PGE can design these programs to ensure equitable practices, we have deployed personnel in the PGE Testbed who are tasked with studying and addressing equity issues. Their work is providing invaluable insights that informs future program design, and leads to the direct, meaningful, and measurable benefits that increase access to flexible load solutions and lower the energy burden of our low-income customers.

1.1.1.1 Long Term Evolution of Program Strategy

PGE's vision for flexible load is a high-value portfolio of grid services that support the decarbonized, decentralized grid through co-optimization of generation and load. Flexible load can move beyond providing peak capacity alone; with automation of control systems, flexible load has the potential to offer high value grid services. Incorporating thoughtful program design and customer centric operations can minimize the impact on customers providing these services.

DR Service Product	
Shed	Capacity
	Energy
	Economic DR
	Emergency DR
	Distribution Deferral
Shift	Time of Use
	Some Behavior Programs
Shimmy	Load Following
	Contingency Reserve
	Frequency Response
Shape	Energy Efficiency
	Some Behavior Programs

Figure 2 – PGE's Vision of Demand Response Services

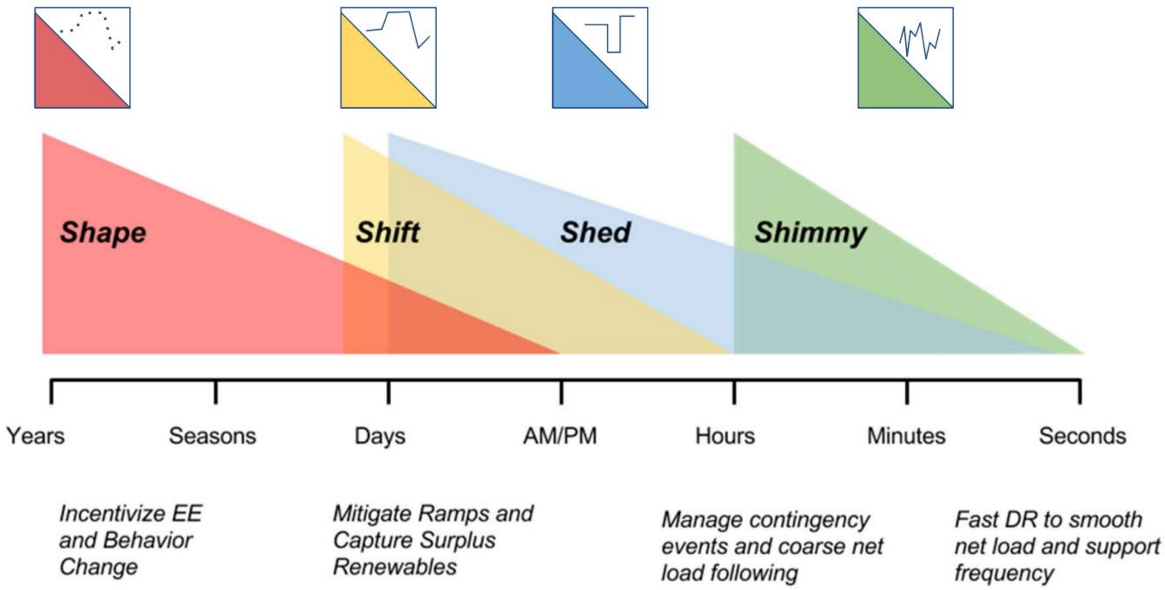

Figure 3 – Evolution of Demand Response and Flexible Load Services

Figure 3 reflects the different planning and operational time horizons of DR and flexible loads, as well as the types of grid services that flexible loads can provide. More detail on the function and requirements of each service are available in section 4.4.1, Flexible Loads as a Grid Service.

Resources that “shape” load operate over years or seasons to reshape the overall load but are not necessarily responsive to system events. These programs help address power costs by reducing the amount of MW to be procured or built to meet peak electric demand. This category includes EE and behavioral programs.

PGE’s program portfolio presently falls into the “shift” and “shed" categories. Generally, such programs are called day-ahead and reduce energy demand for a set number of hours during system peaks. These reductions are accomplished through either a shift in usage, as in our Flex pilot, or through a load shed or shift, as in the Energy Partner program[28].

As technology improves and costs come down, PGE’s flexible load offerings are evolving capabilities to provide grid services in real time as part of a dynamic portfolio capable of optimizing benefits across capacity, energy, and flexibility products. Programs in this category are responsive within minutes or seconds. Additionally, some “shimmy” services, such as frequency response, may be called upon rarely, while other products, such as regulation and load following, are called upon continuously for balancing service.

[28] Within the PGE Smart Grid Testbed, PGE is also using the Peak Time Rebate program to test renewable integration and carbon reduction messaging. These additional use cases offer PGE an opportunity to study the impact of using this program more frequently. The results of these tests inform the way that PGE incorporates flexible load resources into IRP planning and future operations.

PGE's multifamily water heater pilot represents the most advanced form of flexible load. This pilot uses intra-hour dispatch which should prove able to respond to both distribution and wholesale grid needs by providing a flexible product to balance load and generation.

While PGE is excited about the opportunities for flexible load to provide a variety of grid services, building a portfolio that is capable of providing response in all timeframes—Shape, Shift, Shed, and Shimmy—will best enable PGE to co-optimize the flexible load resource to maximize the value across all resources for PGE's customers. This bundling across response times and technologies will enable the creation of Virtual Power Plants.

This vision of flexible load is in harmony with recent Commission decisions to define various use cases for demand side assets. For example, in UM 1751, *HB 2193 Implementing an Energy Storage Program*, the Commission issued Order 17-118 whereby the Commission delineated a series of energy services which a distribution-sited or demand side-sited resource – in this case energy storage – could provide to the grid.

Table 1 – Energy Storage Use Cases[29]

Category	Service	Value
Bulk Energy	Capacity or Resource Adequacy	The energy storage system is dispatched during peak demand events to supply energy and shave peak energy demand. The energy storage system reduces the need for new peaking power plants.
	Energy Arbitrage	Trading in the wholesale energy markets by buying energy during low-price periods and selling it during high-price periods.
Ancillary Services	Regulation	An energy storage operator responds to an area control error in order to provide a corrective response to all or a segment portion of a control area.
	Load Following	Regulation of the power output of an energy storage system within a prescribed area in response to changes in system frequency, tie line loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits.
	Spin/Non-Spin Reserve	Spinning reserve represents capacity that is online and capable of synchronizing to the grid within 10 minutes. Non-spin reserve is off-line generation capable of being brought onto the grid and synchronized to it within 30 minutes.
	Voltage Support	Voltage support consists of providing reactive power onto the grid in order to maintain a desired voltage level.
	Black Start Service	Black start service is the ability of a generating unit to start without an outside electrical supply. Black start service is necessary to help ensure the reliable restoration of the grid following a blackout.
Transmission Services	Transmission Congestion Relief	Use of energy storage to store energy when the transmission system is uncongested and provide relief during hours of high congestion.
	Transmission Upgrade Deferral	Use of energy storage to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to accommodate load growth, regulate voltage, or avoid the purchase of additional transmission rights from third-party transmission providers.
Distribution Services	Distribution Upgrade Deferral	Use of energy storage to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the distribution system to accommodate load growth or regulate voltage.
	Volt-VAR Control	In electric power transmission and distribution, volt-ampere reactive (VAR) is a unit used to measure reactive power of an AC electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity (1).
	Outage Mitigation	Outage mitigation refers to the use of energy storage to reduce or eliminate the costs associated with power outages to utilities.
	Distribution Congestion Relief	Use of energy storage to store energy when the distribution system is uncongested and provide relief during hours of high congestion.
Customer Energy Management Services	Power Reliability	Power reliability refers to the use of energy storage to reduce or eliminate power outages to utility customers.
	Time-of-Use Charge Reduction	Use of energy storage to reduce customer charges for electric energy specific to the time (season, day of week, time-of-day) when the energy is purchased.
	Demand Charge Reduction	Use of energy storage to reduce the maximum power draw by electric load in order to avoid peak demand charges.

Flexible load, DR, and energy storage can all be viewed from an integrated perspective. These services, outlined in *Table 1*, can be supplied by a host of different technologies with various degrees of accuracy, timing, and duration. For example, a thermostat can be operated to reduce peak load for a four-hour period but may also provide more frequent reductions over shorter durations. A battery may be capable of supplying all of the above services for 4+ hours depending on its chemistry, but a water heater may also be capable of supplying many of the same services at a fraction of the cost.

1.2.3.2 Developing the Virtual Power Plant

PGE is building DR and flexible load with an end-state in mind whereby flexible loads act in concert, aggregated at the substation level; this concept has been dubbed a "Virtual Power Plant". Virtual Power Plants are unique to the assets behind the substation; in other words, a Virtual Power Plant's operational profile is limited by the specific flexible load technologies that are aggregated at each substation[30]. A Virtual Power Plant operates to service energy needs below the substation on the distribution system and energy needs above the substation on the bulk energy system.

Advanced visualization and operation controls are needed to manage and operate a Virtual Power Plant, as not all Virtual Power Plants can supply the same services in the same way. Additionally, each Virtual Power Plant may have local distribution infrastructure constraints. Each Virtual Power Plant must service distribution system operation requirements first and may therefore provide different grid services. Additionally, a Virtual Power Plant may be able to provide different grid services at different times. For example, a Virtual Power Plant that is primarily providing distribution system deferral could also provide regulation reserves when the system is not constrained.

In order to the manage Virtual Power Plant PGE is building an Advanced Distribution Automation System (ADMS) as part of the integrated grid. The ADMS system includes an advanced communication network to allow near real-time visualization of the health and operation of the distribution network and to provide monitoring of the availability of local Virtual Power Plant services.

As PGE builds more advanced DR and flexible load programs, it is essential that this work is done in concert with the investments in ADMS to provide the communication capabilities and networks necessary to use the resource for grid services and be able to visualize the resource either individually or as part of a Virtual Power Plant. These communications are necessary for flexible loads to provide the grid services that require dispatch and communications in real time.

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[29] Modified from Akhil et at.2015., Oregon Public Utility Commission UM 1751, Order 17-118, March 2017, page 17.

[30] For example, one substation's Virtual Power Plant may see a predominance of solar and battery storage; another substation's Virtual Power Plant may be primarily demand response.

1.2.4 *Device Data, Resource Development, and the Customer Experience*

PGE is developing flexible load demonstrations, pilots and programs to empower our customers to control their overall energy costs, reduce system costs, decarbonize and provide benefit to the community while maintaining reliability. Our work in the Testbed is researching and testing different ways to engage with our customers and to communicate the value of participating in flexible load programs. PGE's current DR activities are providing bill savings and participation opportunities for all customers. These programs are first and foremost efforts to better meet our customer needs. PGE is working to build a portfolio of flexible load programs which benefits all customers and allows customers to engage with and participate in a decarbonized energy platform.

PGE customers expect to have an excellent experience with flexible load programs; these positive customer experiences create ongoing success for these programs. Additionally, customers deserve to know and understand how participation in these programs drives meaningful change, whether through reductions in cost, meeting decarbonization goals, or supporting their community.

For PGE to have effective relationships with customers, PGE will need to reshape how customer information and data is shared. PGE must also leverage technologies made by other manufacturers whether a solar inverter, a water heater or a thermostat. These technologies will help shape the customer experience, the resource, and grid operations. OEM terms and conditions place limits on data access. Thus, access to data is increasingly more important to PGE and to the expansion of flexible load program capabilities.

As explored further in Chapter 3, PGE would like to open a discussion with the Commission to address data sharing.

1.3 Planning Practices

PGE has a long history of planning for DR programs within the IRP process. In the early 2000s, PGE explored the potential for DR pilots, including direct load control (DLC) of space heating and water heating, to contribute to meeting our capacity needs. Over time, PGE's approach to evaluating demand response and flexible load in the IRP has gained sophistication, largely by leveraging outside expertise through a series of demand response potential studies. PGE first conducted a third party DR potential study as a joint exercise with PacifiCorp in 2004 as a result of OPUC Order No. 03-408[31]. PGE subsequently contracted with Quantec, LLC to update the

[31] Available at: https://app.nwcouncil.org/media/4502/dr_assessment.pdf.

study to inform the 2007 IRP[32] and with Brattle to conduct potential studies to inform the 2009, 2013, and 2016 IRPs.[33,34,35]

Demand response potential studies typically involve three steps:

1. **Quantifying the technical potential**, or the amount of the resource that is technically possible, without consideration of cost or other market barriers. It considers all measures or resource opportunities, the savings associated with each, and the number of opportunities to implement or install each resource over a 20-year planning period.

2. **Determining the achievable potential,** which accounts for market barriers, as well as technology and market maturity. Historically, EE planners in the Northwest have assumed that market barriers limit achievable potential to no more than 85% of technical potential. This maximum achievability assumption is based on the 1980s Hood River Conservation Project funded by the Bonneville Power Administration[36]. In the context of DR and other flexible load resources, this maximum achievability assumption would vary depending on the type of resource being considered, as the market barriers to acquiring flexible load resources may be more significant than those of EE[37]. Achievable potential[38] also employs curves called ramp rates to quantify the amount of potential acquired in a given year out of the total technical potential available. Ramp rates reflect program maturity, technology maturity, market readiness, and program budgets.

3. **Applying an economic screen,** which determines the amount of potential that is cost effective for PGE to pursue. The economic screen involves an estimation of costs and benefits of each program and a cost effectiveness determination based on an agreed upon cost effectiveness framework. Cost effectiveness is discussion in more detail in Chapter 4.

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[32] See Section 4.3 in PGE's 2007 IRP, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc43haa105740.pdf.
[33] See Section 4.2 in PGE's 2009 IRP, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc48haa151359.pdf.
[34] See Section 4.2 in PGE's 2013 IRP, available at: https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/pge-2013-irp-report.pdf?la=en.
[35] See Section 6.3 in PGE's 2016 IRP, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc66haa144338.pdf.
[36] The Hood River Conservation Project was intended to test the upper limits of a utility retrofit program. HRCP sought to install an extensive package of retrofit measures in all the electrically heated homes in Hood River, Oregon. The results from the Hood River Conservation Project form the basis for the energy efficiency planning in the Northwest and nationally today.
[37] To date, there has been no similar study on DR or flexible load saturation potential.
[38] Note that some potential assessments also consider program potential, but the same considerations that define program potential can be considered as part of the determination of achievable potential.

These steps are summarized in Figure 4

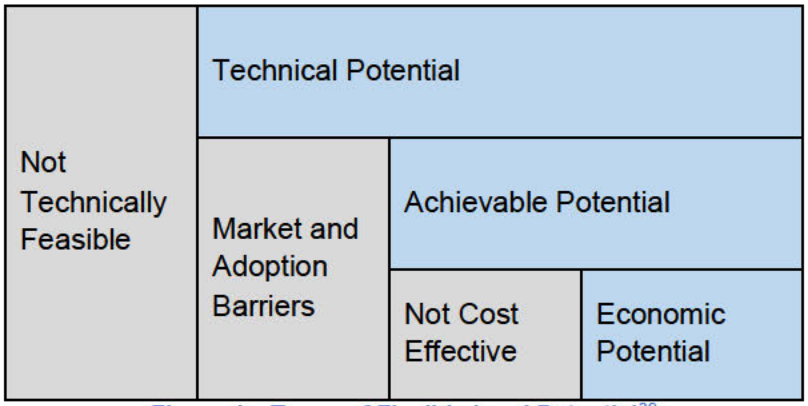

Figure 4 – Types of Flexible Load Potential[39]

PGE's approaches to incorporating the results of demand response potential evaluations into IRP analyses and the IRP action plans have evolved over time. PGE incorporated a DR forecast into the 2009 IRP based on the potential from the Brattle Study, with adjustments built on PGE's experience and the specific activities that the Company planned to undertake. PGE incorporated DR forecasts into the 2013 IRP based on the findings in the Demand Response Potential Study conducted by Brattle Group.[40] The work was further informed PGE's assessment of participation in the Company's curtailment tariff. In the 2016 IRP, PGE again improved on DR forecasting; PGE developed a DR portfolio based on the DR potential study but adjusted the DR portfolio for potential interactions between programs. This adjusted DR portfolio went into the preferred portfolio and was ultimately reflected in the IRP Action Plan.

In the 2019 IRP, PGE leveraged the information from the DR Potential Evaluation from the 2016 IRP to inform a broader study of DERs. The 2019 IRP Navigant Distributed Energy Resources Study applied customer propensity to adopt models across a wide range of DERs, including DR. The study developed an internally consistent set of low, reference, and high DER adoption scenarios that accounted for interactive effects between DERs, including DR programs.[41] The study resulted in three DER adoption scenarios (low, reference, and high), which flowed into PGE's IRP needs assessment and portfolio analysis and Action Plan. The study developed an internally consistent set of low, reference, and high DER adoption scenarios that accounted for

[39] Adapted from U.S. Environmental Protection Agency. *Guide to Resource Planning with Energy Efficiency*. Figure 2-1, November 2007

[40] PGE 2013 IRP Report, Section 4.2 Demand Response Potential Study, available at https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwjlpf-wiIXqAhUiHzQIHYIpDAIQFjAAegQIAhAC&url=https%3A%2F%2Fwww.portlandgeneral.com%2F-%2Fmedia%2Fpublic%2Four-company%2Fenergy-strategy%2Fdocuments%2Fpge-2013-irp-report.pdf%3Fla%3Den&usg=AOvVaw1WtS_gz367mTEVdY7OXDjD

[41] See Section 5.1.1 in PGE's 2019 IRP, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc73haa162516.pdf.

interactive effects between DERs, including DR programs[42]. The study resulted in three DER adoption scenarios (low, reference, and high), which flowed into PGE's IRP needs assessment and portfolio analysis and IRP Action Plan.

The studies to support long term planning over the last five IRPs have helped PGE to develop a more nuanced understanding of DR and to incorporate more rigorous treatment of DR over time. The studies have also helped inform the design of new DR programs by leveraging those consultants' outside expertise and insights. While this work has been integral to PGE's continued progress on planning for and implementing DR programs, it has also created some challenges that are worth considering as PGE contemplates alternative planning approaches:

- DR forecasts produced by these studies are exogenous to IRP modeling. This means that PGE cannot readily test potential interactions between new resource additions and alternative DR portfolios, potentially resulting in sub-optimized DR targets. This is a similar challenge to the EE forecasts from the Energy Trust.
- The studies incorporate limited information from PGE's actual deployment of DR programs, and therefore may be influenced more by national trends than local circumstances.
- The studies have limited transparency and ability to update input assumptions and incorporate learnings due to outside experts' use of proprietary models.

In the past, the insights provided by the outside studies have outweighed these drawbacks. However, as the role of DR grows in PGE's portfolio, the relative impact of some of the shortcomings of these exercises also grows. PGE discusses new potential approaches to planning for flexible load within the IRP and DRP process in Chapter 2.

1.4 Program Information

1.4.1 Chapter Synopsis and Road Map

This Section is a high-level review of PGE's current Flexible Load portfolio, including brief descriptions of each activity. A ribbon at the top of each description shows total costs of the life of the activity, size of the resource in megawatts, and the date of the next expected evaluation.

PGE includes these program descriptions to ground the reader in PGE's current program activities. In the remainder of this document, PGE refers back to these programs to provide examples that illustrate how PGE is enacting the programmatic and product changes described in Chapters 2-4. PGE also includes a more detailed write-up of each activity in Appendix 1 of this filing. This Chapter does not contain a proposal for Commission action; rather this Chapter and Appendix 1 serve as a demonstration of PGE's continued commitment to open and transparent

[42] See Section 5.1.1 in PGE's 2019 IRP, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc73haa162516.pdf.

reporting, and a reference for the remainder of this document. Readers who are familiar with PGE's programs may wish to jump to Chapter 2.

The collection of PGE's flexible load program work is an impressive advancement in PGE's programs and capabilities since the initial ramp-up to meet the 2016 IRP DR goals. Each of these activities targets a unique space within the flexible load resource ecosystem. Multifamily water heater is proving the use case for a fast-acting, flexible load resource. Water heaters are ubiquitous in electric homes and are capable of providing year-round grid services multiple times a day while minimizing customer impact. The Flex pilot is proving DR and the benefits of customer participation without requiring capital investment by the customer. The Flex pilot will demonstrate a variety of participant values to our customers. These customer value propositions are being explored in the PGE Smart Grid Testbed (Testbed).

1.4.2 Non-Residential Demand Response Energy Partner Program

Total Costs	Megawatts Procured	Next Evaluation
$9.8M (Jun 2017 to EOY 2020)	21.8 MW	Q2-2021

1.4.2.1 Program Description

PGE established Energy Partner as a non-residential DR program designed to reduce peak demand requirements during specific time windows in the winter and summer seasons. The primary source of this reduced demand (load) is from large customers, with an option for small and medium customers to participate as well. The Energy Partner Program provides firm capacity and may evolve to provide intra-hour grid services to support reliability and renewables integration. The 2018 target was 14MW of DR, increasing to 20MW for 2019, and ultimately reaching 27MW by January 1, 2021.

PGE launched its non-residential DR pilot in December 2017 and directly administered the pilot with support from:

- CLEAResult for program implementation; and
- Enbala for technology integration via their Virtual Power Plant software platform.

In 2017, PGE found that the selected third-party administrator was falling short of load goals and began taking a more active management role in the prior "turnkey" DR program. PGE's active management proved beneficial for multiple reasons. First, it provided PGE the flexibility to develop a variety of product offerings and to adjust the offerings as necessary in the future. A second reason for PGE to work directly with customers is portfolio resiliency. With the loss of the third-party demand response provider in 2017, PGE had to execute new contracts and deploy new technology to current participants which presented customer retention risk. Directly administering the program should avoid such operational risks. PGE's administration of the program also allows for better bundling and/or cross-marketing of the program with other offerings such as EE, renewables, storage, and dispatchable standby generation.

As Energy Partner matures, it may evolve from solely a capacity resource to other use cases such as load following and renewable firming. Including business DR provides an opportunity to accelerate learnings, as well as test and optimize new use cases.

1.4.3 Multifamily Water Heater Pilot

Total Costs	Megawatts Procured	Next Evaluation
$4.1M (cumulative through EOY 2019)	3.4MW	Summer 2020-21 (due in March 2022)

1.4.3.1 Program description

The Multifamily Water Heater pilot aims to enable and operate electric water heaters for demand flexibility. This program provides capacity as well as intra-hour energy and lays the foundation for PGE's DR programs to offer intra-hour grid services to support reliability and renewables integration. The approach is relatively novel as it capitalizes on the density of electric water heaters found in multifamily dwellings. This density is necessary for several reasons:

1. Broadly-distributed assets are more expensive per unit installation, whereas concentrations of units allow PGE to enable water heaters for a fraction of the cost;
2. Many multifamily units install the water heater within the living space using electric resistance water heaters. Installation of heat pump water heaters is not a common practice. This niche allows PGE to test advanced use cases from electric resistance water heaters without affecting the Energy Trust's and the Northwest Energy Efficiency Alliance's (NEEA) efforts to promote adoption of more efficient heat pump water heaters;
3. Installing a concentration of these units in multifamily buildings provides PGE an opportunity to accelerate working with water heaters as a flexible load resource compared to current deployments of DR enabled heat pump water heaters.

Water heaters provide a cost-effective approach to supplying grid services. PGE developed the Multifamily Water Heater Program to learn about the connectivity and controllability of a flexible load resource from a highly dynamic, ubiquitous appliance. PGE's learnings from this pilot will also help inform our approach to single family water heaters.

1.4.4 Smart Thermostat Pilot

Total Costs	Megawatts Procured	Next Evaluation
$5.5M (Cumulative through EOY 2019)	13.7MW	Summer 2020 (due July 2021)

1.4.4.1 Pilot Description

The Direct Load Control Smart Thermostat Pilot aims to enroll and operate connected residential thermostats to control electric heating and cooling load. This program provides firm capacity; PGE is working with the Energy Trust to explore how thermostats and other efficacy measures can be paired to provide longer duration energy optimization. To participate in the program, PGE customers must have a qualifying heating, ventilation, or air conditioning (HVAC) system (ducted heat pump, electric forced-air furnace, or central air conditioner). The pillars of the pilot rest on two delivery channels:

1. **Bring Your Own Thermostat.** Customers may enroll online in PGE's DR program by purchasing a new qualifying thermostat, or using an existing qualifying thermostat attached to a qualifying HVAC system. Customers receive a $25 enrollment incentive and $25 for each DR season that they participate in (defined as 50% of the DR hours called within a season). Customers are permitted to opt-out of any or all events.

2. **Residential Thermostat Direct Installation.** Customers with a qualifying HVAC-system can participate by having a qualified thermostat, installed, provisioned, and enrolled into PGE's DR platform by a PGE contractor. This channel provides a no cost thermostat for customers with ducted heat pumps or electric forced air furnaces due to the high DR capacity value. Customers with central air conditioners are charged an incremental cost of $50. Customers from this channel are excluded from receiving PGE enrollment or seasonal participation incentives.

1.4.5 Flex 2.0 - Peak Time Rebate and Time of Use

Total Costs	Megawatts Procured	Next Evaluation
$3.9M (Cumulative EOY 2019)	6.9MW	Estimated August 2022

1.4.5.1 Program Description

This pilot provides energy optimization by alerting residential customers to shift use out of high demand periods and deliver peak reduction.

In 2016, PGE launched a two-year Residential Pricing Pilot (Flex 1.0) in which a combination of 12 opt-in and opt-out Time of Use (TOU), Peak Time Rebate (PTR), and Behavioral DR (BDR) scenarios were tested. Approximately 14,000 customers were enrolled in control or treatment groups and provided valuable insights into customer response to, and expectations of, programs of this nature. In June 2018, Cadmus completed an independent evaluation of the Flex 1.0 pilot and confirmed that PGE can cost-effectively obtain demand savings through pricing and behavior-based DR programs and offered specific recommendations on those scenarios that delivered both the highest value and levels of customer satisfaction.

Based on those findings, PGE worked with OPUC staff and stakeholders to develop the Flex 2.0 "Residential Pricing Pilot". The first step for implementing Flex 2.0 was launch of a PTR program in April 2019. The vast majority of PGE's residential customer base is eligible to participate in this voluntary program, and 77,000 residential customers enrolled in the pilot on an opt-in basis by the end of 2019, exceeding our Year 1 enrollment goal by 40 percent.

The PTR pilot provides educational energy saving tips and rewards customers for shifting their energy usage during 3-4 hour "event" periods. Customers are notified a day ahead of the event via text and/or e-mail (based on their preference). After the event, they are notified of the result of their specific effort and, if applicable, their earned incentive. There is no "penalty" should a customer use more than expected energy during an event, making PTR a no-risk, "win-only" program for our customers.

PGE is working with OPUC Staff on the design of a new TOU rate and plans to submit a revised Schedule 7 tariff to include the new pricing structure in Q2/Q3 2020. The TOU pricing plan could be combined with PTR to enhance year-round savings and provide daily load shift value to PGE.

1.4.6 Residential Battery Energy Storage Pilot

Total Costs	Megawatts Procured	Next Evaluation
$66K	160kW	Est. June 2021

1.4.6.1 Program description

Behind the meter batteries are considered flexible load as they will adjust customer load and are expected to provide a host of valuable grid services. In the Single-Family Battery Pilot[43], a fleet of batteries will act in aggregate to provide grid services; individually they will provide customer services. The Battery Pilot will provide capacity, grid services, and home energy back-up for the customer. While PGE has established the value of some grid services through modeling, this pilot will confirm this value through operational demonstration and establish values for other services that are difficult to model. The pilot intends to aggregate 525 residential batteries totaling 2-4MW

[43] These batteries are cited on the customer side of the meter and are thus included in the definition of "flexible load" while other utility-scale pilots do not meet this definition.

in size and 6-8MWh in duration. Each battery will provide between 3-6kW of power output and 12-16kWh of energy storage.

In April 2020, PGE submitted a proposal[44] to the Commission to leverage battery energy storage systems installed on residential customer homes. These battery systems will be located behind the utility electric meter and serve as a dispatchable resource providing a range of grid services.

[44] PGE filed Advice No. 20-08, Schedule 14 Residential Battery Energy Storage Pilot, on April 21, 2020, with a requested effective date of August 1, 2020.

Chapter 2 Planning, Goal Setting, Regulatory Treatment

Chapter Summary

Chapter 2 of the Flexible Load Plan requests action from the Commission regarding PGE's proposal to move to multiyear planning and budgeting. The proposal includes regular quarterly engagement and updates with Commission Staff, as well as regular report submittals to the Commission regarding progress, spending, and savings. This is a change in practice from current single measure development and cost recovery to portfolio-level planning and cost recovery. PGE's proposal is informed by best practices undertaken in the Northwest around energy efficiency planning, funding, and acquisition. The proposal is meant to give the Commission, Staff, and stakeholders an extraordinary amount of transparency and collaboration regarding PGE's work to develop flexible load.

Chapter 2 also discusses PGE's evolved planning and measure development practices. Within this Chapter, PGE shares how we conduct measure development and strategic market engagement. PGE calls this process Product Lifecycle Management (PLM). It is a stage-gated process that judges a product's market readiness. The PLM process is informed by practices from the private market and is similar to the process used by the Northwest Energy Efficiency Alliance (NEEA). PGE requests understanding from the Commission and stakeholders as to why we have created an evolutionary type of measure development which starts at demonstration, before moving to pilot, and finally program.

PGE efforts to develop flexible load are leading the region, but we do not have the benefit of regional co-development, as granted to energy efficiency. Therefore, PGE will need to identify planning values and validate technologies through small demonstration work, much of which will leverage the PGE Testbed. Such activities and investments in energy efficiency are generally shared by the region. PGE has designed this measure development structure to accelerate measure development while controlling costs. Whereas in the past, PGE's single measure planning, funding and pilot-to-program scaling work has been, to an extent, siloed, the structure shared in this chapter should addresses cost, cost effectiveness, and program scaling issues that PGE is currently managing within our present program offerings.

Lastly, Chapter 2 gives the reader insight into our customer outreach and diversity, equity, and inclusion (DEI) practices and how they will inform measure development. Chapter 2 also attempts to connect our DRP, Smart Grid and IRP work to the activity outlined in the Flexible Load Plan. The inclusion of this discussion is not meant to displace or replace the need or requirements of the other individual reports, nor is it meant to influence the activity in UM 2005. We provide this discussion only in attempt to make connections for the reader and our stakeholders.

2.1 Chapter Synopsis and Road Map

This chapter is the focal point of the Flexible Load Plan, as it sets forth PGE's proposal to move to portfolio level planning and budgeting. It also proposes a shift in regulatory practice to align with Demand Side Management (DSM) best practices seen throughout the Northwest and the nation.

PGE proposes to move to a multiyear planning and budgeting framework to align with the targets established through our resource planning process. PGE also proposes to provide annual updates to the proposed multiyear plan which details program implementation and operation. Further PGE would provide bi-annual budget updates for the first two years after which PGE would shift to annual budget updates. This proposed framework allows PGE to plan over a period of years with a known budget that can be used across a portfolio of activity. Cost effectiveness will be measured and reported at both the measure and portfolio basis. This proposal is similar to the practices of other regional utilities operating DSM and the planning framework employed by the Energy Trust and NEEA.

Additionally, this chapter communicates PGE's movement to a new product lifecycle framework, an internal process known as Product Lifecycle Management. This process is intended to ensure cross functional input and program development, among other things. Additionally, PGE communicates a shift in our strategic program development within the new construction market (to leverage delivery savings) and the retrofit market (by offering a bundled approach to all DSM and flexible load offerings, including close coordination with EE delivery). Lastly, this chapter reviews our IRP treatment of Flexible Load and discusses how Flexible Load will be incorporated into distribution system planning. This chapter also communicates PGE's commitment to reporting to the Commission, Commission Staff and stakeholders.

2.1.1 Introduction

As noted in the introduction, the Pacific Northwest has been investing in energy efficiency since 1980. Forty years of investment has allowed the region's utilities to establish best practices for development, procurement, modeling and reporting; these practices are emulated across the country. PGE's review of Northwest DSM practices informs the proposal below. This review indicates that PGE should adopt multiyear planning, coupled with multiyear budgeting and portfolio acquisition as a best practice to achieve both sustained programmatic success and cost effectiveness. These practices should be coupled with yearly updates and regular reporting to the Commission and stakeholders to provide transparency and accountability.

2.2 Practice Change Framework

PGE's Flexible Load Plan is a demonstration of PGE's commitment to a new type of resource development and new procurement practices with the goal of building advanced flexible load programs through a customer centric partnership. The Flexible Load Plan also demonstrates PGE's embrace of new approaches to strategic planning, project/product/program design, organizational structure, stakeholder engagement, and cross-utility collaboration.

PGE, with guidance from the OPUC, is pursuing innovative, customer-focused programs using flexible load technologies embedded in the distribution grid. These technologies present novel challenges to all parties. Decarbonization of Oregon's economy is a goal embraced by PGE, our customers, the OPUC, and the State of Oregon. Achieving this goal requires PGE to innovate and deliver measurable customer value and benefits. An effective demonstration-to-pilot-to-program lifecycle is critical to accomplishing our collective decarbonization and flexible load resource development goals.

PGE instituted a framework which utilizes five essential pathways to flexible load resource development[45]. Table 2, is a representation of these five essential pathways:

Table 2 – Five Essential Pathways to Innovation and DSM Resource Development

Strategic Planning	**Implement a long-term strategy for program development, cost control, transparency and collaboration**
Designing to Scale	**Design demonstrations and pilots to maximize learning and prepare for full scale deployment**
Organization	**Create leadership support and accountability, dedicated resources and cross functional collaboration within the utility for effective program development**
Stakeholder Engagement	**Collaborate effectives across industry stakeholders to design and execute meaningful projects**
Cross-Industry Collaboration	**Share best practices and lessons among utilities to accelerate effective demonstration, pilot to program evolution**

[45] Note: this section focuses on program development; program operations and evaluation are covered separately in detailed program write-ups in the appendix to this document.

2.2.1 Strategic Planning

Over the last four years, PGE has emerged as a national leader in developing the flexible load resource. PGE's leadership in this space is primarily due to the top-down alignment of flexible load with the Company's corporate strategy to decarbonize, electrify, and perform. Flexible load resources are significant to PGE's future and our ability to deliver a clean energy future to our customers and community. Therefore, it is essential to have a long-term strategic plan for product and program development that ties the Company's three strategic imperatives to flexible load products and programs.

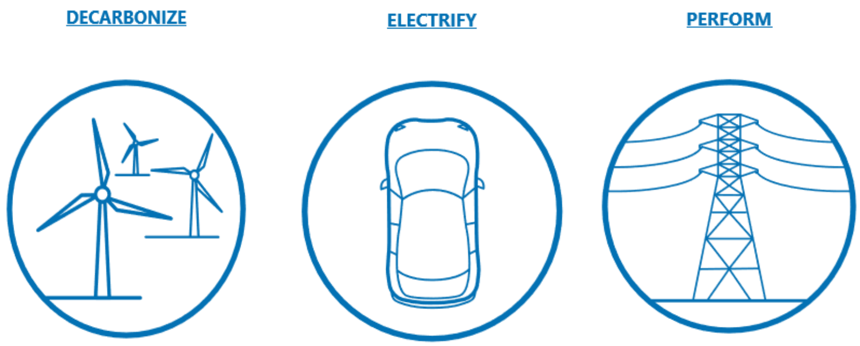

Figure 5 – PGE's Long-Term Imperatives for a Clean Energy Future

2.2.1.1 Decarbonize

PGE, in partnership with our customers and community, has chosen climate action. Increasingly, our customers want their energy choices to be cleaner than ever. To that end, in 2018, more than 90 percent of PGE's energy supply is generated right here in the Pacific Northwest. PGE is committed to reducing our greenhouse gas emissions by more than 80%. PGE recently announced a renewable energy facility, Wheatridge, that is the first-of-its-kind in North America, combining wind and solar energy with battery storage at scale. Additionally, PGE has emerged as a leader in developing flexible load resources, as exemplified by our pioneering work on the Smart Grid Testbed. The Testbed is implementing simple customer solutions, devices, and behavioral changes to reduce the carbon in PGE's system and reduce investments in large generation resources.

2.2.1.2 Electrify

Approximately 35% of Oregon's end use demand for energy is currently served by electricity; the rest is served by served by direct combustion of natural gas and petroleum.[46] To help our customers meet their goals of driving decarbonization of the entire economy, PGE will lead the way through beneficial electrification pilots and programs that impact end uses like transportation – powering society with energy that we make cleaner every day. In doing so, PGE will capture

[46] Oregon Department of Energy. 2018 Biennial Energy Report. *Available At:* https://www.oregon.gov/energy/Data-and-Reports/Documents/2018-Biennial-Energy-Report.PDF

the benefits of new technology, leading to an increasingly flexible and reliable grid and the connectivity and controllability needed for a Virtual Power Plant.

2.2.1.3 Perform

PGE is at its best when we deliver what customers want, namely affordable, reliable, cleaner energy choices. This is particularly critical as society undergoes a clean energy transformation. PGE seeks to serve and provide equitable access to all customers, not just the most profitable. PGE knows that the heart of business is keeping the power on safely, reliably, and affordably. To keep the grid running smoothly, PGE must continue to increase efficiency. PGE also seeks to deliver exceptional customer experiences, which includes empowering and enabling our customers to control their total energy costs by providing them new platforms to extract benefits from our service. Flexible load programs allow PGE to perform to our customers' expectation and standards.

2.2.2 Designing to Scale

PGE is implementing a new framework for program development. The first stage of this process focuses on smaller scale demonstrations of technology, product, and approach. Successful demonstrations continue on to a pilot stage, with controls to appropriately manage the progression to scale and to achieving cost effectiveness. The objective is to produce a long term, cost effective program with stability of approach, customer experience, and predictable costs and performance.

2.2.3 Organization

In the past two years PGE hired new leaders, new talent, and reorganized our customer programs, services, and support groups to overcome organizational silos and competing priorities. These groups are accountable to senior leaders through yearly accountability goals and scorecards which assess performance of the individual, team, and management. For example, the performance of the Smart Grid Testbed affects the assessment of the Team's most senior leader - the Vice President of Grid Architecture, Integration, and System Operations, Larry Bekkedahl. Additionally, PGE has created a Product Life Cycle Management process to engage business units across the utility in the design, execution, evaluation, and scaling of our flexible load projects.

2.2.4 Stakeholder Engagement

Stakeholder engagement and support is essential for meeting the aggressive, innovative goals that PGE and the OPUC have adopted for flexible load deployment. To ensure meaningful and beneficial stakeholder engagement in the development of flexible load resources, PGE designed its Product Lifecyle Management process to assess the necessary level of engagement for each of phase of the lifecycle. Varying levels of stakeholder engagement will exist for the ideation, design, implementation, and evaluation of resources. PGE's stakeholder engagement activities are described in more detail in Section 3.6, below.

2.2.5 Cross Industry Collaboration

As noted above, industry collaboration is key to the Company successfully delivering flexible load resources that will ultimately culminate in a Virtual Power Plant. PGE has been working to establish coordination with the Energy Trust through the Smart Grid Testbed advisory groups and regular monthly coordination meetings with the project team. Additionally, PGE has recently opened a conversation with PacifiCorp about co-development of demonstration and pilot projects that may offer enhanced customer experience and cost saving opportunities. PGE has also engaged with the Northwest Energy Coalition (NWEC) and NEEA about sharing lessons learned from our work and furthering regional collaboration. Lastly, PGE has been sharing our work with the region through various regional forums such as the NWPCC's Demand Response Advisory Council and GridFWD and nationally through the Electric Power Research Institute (EPRI) and the Peak Load Management Alliance (PLMA).

2.3 From Demonstration, to Pilot, to Program Lifecycle

Designing to Scale	Design demonstrations and pilots to maximize learning and prepare for full scale deployment

Much of PGE's flexible load resource was developed as DR or pilot activity. The arc of this development was circumstantial. In the lead up to PGE's 2016 IRP, the company had less than 15MW of DR procured through a single large commercial and industrial program. In the 2016 IRP, PGE identified 77MW/69MW of Winter/Summer DR potential capacity available on its system. As part of Order 17-386, the Commission adopted the identified DR potential as PGE's goal for 2021. When reviewing PGE's proposed 2016 IRP DR goals, Staff noted its concern that PGE was "stuck in a pilot cycle."[47]

In the same docket, the Commission issued a white paper on the concept of a DR Testbed as a tool for accelerating the demonstration to program lifecycle as part of an acknowledgement that the acquisition of 77MW/69MW by end of year 2020 was a necessary but challenging task.[48]. In turn, PGE pursued the rapid development of a DR resource with the understanding that these efforts were novel and thus required the regulatory latitude that comes from conducting pilot activity. While the initial build of PGE DR activity would not be cost effective, PGE has an

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[47] LC 66, Staff's Final Comments, Page 22, May 12, 2017

[48] LC 66, Staff's Final Comments, Appendix A Demand Response Testbed Overview. "The fundamental purpose of the DR Testbed is to test a number of hypotheses and critical assumptions about the potential of DR in the Northwest that are difficult or impossible to obtain during the initial rollout of PGE's proposed DR programs. Without such a concerted effort, and in light of the Brattle study results (imperfect as they are) and the recent information from the NWPCC about the value of DR to the region, the prudence of PGE selecting lower acquisition targets without answering fundamental questions about actual DR resource potential in its service territory would be in question.
Time is also of the essence in order to address the potential gap identified in 2021. PGE cannot wait to begin deployment of its proposed DR programs, so Staff is interested in near term actions that are consistent with the larger long-term strategy and goals."

obligation to demonstrate a pathway to cost effectiveness. Details on PGE's pathway to cost effectiveness are in Chapter 3.

In pursuit of the 2016 IRP DR goals, PGE launched a series of development acceleration activities, including business practice changes, team augmentation, technical assistance, IT development, customer bill coordination, evaluation activity, market studies, and customer insight studies.[49] Past challenges with PGE's DR programs have been incorporated as learning opportunities that inform PGE's current demonstration-pilot-program approach for building innovative grid services products. Moreover, these learnings will influence our efforts to meet our 2021 DR capacity goals.

Compared to many other utilities across the country who do conduct demand response program PGE lacks a strong, well-established, large commercial and industrial customer base. Many of the large industrial and commercial customers in PGE's service territory have chosen to take service from Electricity Service Suppliers. Thus PGE, unlike other utilities nationally, needs to procure most of its DR from residential and small commercial customers. Sourcing DR from residential and small commercial customers requires certain program adaptations. Before program launch, PGE must invest in educating a broader customer base. Program offerings must be simple, acceptable, stable, and convenient.

To date, PGE has built its DR pilots independent of one another. The Company has relied on prior demonstrations and pilot activities, as well as national meta-study information, to build cost estimates for DR resources. This approach has led to individual product forecasting and multiple deferral filings, instead of portfolio level forecasting and cost recovery planning. More explicitly, because of this approach, each pilot or offering has its own budget, IT solution, personnel, evaluation process, tariff, and cost-effectiveness analysis. Thus, PGE's attempts to build DR resources have met a series of consequential and interrelated financial challenges, discussed later in this chapter, Chapter 3 and Appendix 1. PGE's 2016-2021 demand response resource development cycle has informed us that financial planning at the portfolio level is necessary to increase strategic alignment and cost savings.

Over the span of four short years (2016-2020), PGE has learned key lessons regarding the pace at which to scale a flexible load resource. These lessons are reflected in the demonstration-pilot-program process detailed in this chapter. They also inform program improvements that are enabling PGE to meet our 2016 IRP DR goals, as well as future flexible load goals.

PGE has begun moving to a portfolio level view for pilots and products. A portfolio view allows us to capture the financial value associated with a group of pilots or products, similar to practices employed by EE providers. This approach appropriately aligns portfolio goals with our overall business strategy and provides opportunities for PGE to be nimble by integrating ongoing improvements and shifting investments to the strategies that prove effective.

[49] PGE conducted a series of customer surveys to identify customer awareness, understanding and wiliness to participate in utility guided programs.

PGE has developed a resource build with an evolutionary concept and framework, moving through the demonstration-pilot-program process. PGE first accelerated efforts to meet our 2016 IRP DR goals by developing resources as pilots[50]. In this filing, PGE proposes a three-step evolutionary process:

1. **Demonstration stage** – Demonstrations are initial, small-scale efforts designed to prove the viability of a technology, hypothesis, or idea; or to answer discrete technical and/or customer-related questions. Demonstrations may involve either the exploration of novel technologies or ideas or the application of existing technologies. Demonstrations enable PGE to manage the risks of new ideas and identify any key problems or issues before committing substantial resources resource and time Within the Smart Grid Testbed, PGE is conducting numerous demonstrations to explore the capabilities of new products and practices, and identifying if, when, and how these products and practices can be integrated into PGE operations.

2. **Pilot stage** – Pilots are limited-scale efforts designed to validate the business case and manage the implementation risks associated with successful demonstrations or other projects that have attained a certain level of readiness as defined by PGE's Product Lifecycle Management process. Pilots test the implementation, customer engagement, and marketing approach, test customer satisfaction and acceptance, provide final validation of the business case, and demonstrate cost effectiveness or identify a pathway to cost effectiveness. Pilots help PGE, the Commission, and stakeholders assess whether an offering is ready to become a program, where it becomes a permanent part of PGE operations. Many of PGE's current activities, such as Peak Time Rebates and Smart Thermostats, are in pilot phase.

   Pilots are a way to test a new idea believed to provide potential benefits to ratepayers in a manner that minimizes risk. If the pilot is successful, it can be rolled out for wider adoption and incorporated into base rates. If the pilot is unsuccessful, it can be discontinued or redesigned. Pilots, as covered in this document, include projects such as research studies, product demonstrations, "field tests". A pilot is not a required step before adopting a service or practice.

   This process does not cover research activities paid for through existing R&D budgets. R&D budgets, O&M budgets, and other such sources that are determined as part of base rates can be utilized to fund research projects, initial market research, tests, or "demonstrations."

   Pilots are intended to test an idea that has the potential, if supported by learnings from the pilot, to be widely rolled out to customers. Pilots demonstrating stability

[50] PGE launched a series of pilots, including a multifamily water heater pilot, a smart thermostat pilot in coordination with Energy Trust, a unique redesigned commercial and industrial customer offer through Energy Partner, a peak time rebate customer offering and a first-of-its-kind Testbed.

and certainty of concept or practice can move to the program stage. During the pilot stage, the core concept is tested and a strategy for implementation is developed. If appropriate, a transition plan for rollout should be developed.

3. **Program stage –** Programs are the last evolutionary step wherein an activity is cost effective, performance is stable and reliable, and the budgets are forecastable within an acceptable tolerance. Programs should deliver a product or service at scale. Since a program is a sustained and discrete offering, the program should have well-defined scope. Similar to pilots, but to a lesser degree, programs can also have such restrictions or parameters as the number of subscribers, the total spend, and requirements to avoid shifting costs. The key feature that distinguishes a program from other activities is its ongoing nature. Staff has reiterated that this guidance addresses new and emerging programs, and does not apply to well-established, existing practices.

Figure 6 shows PGE's program evolution process. The size of the activity grows as the maturity of the product, program, or service moves through the evolution. PGE is moving each of our initial 2016 IRP DR resource build activities through this process in pursuit of each becoming a mature program offering. Later in this chapter, PGE details the recommended pilot-to-program criteria. Each program write-up within A.2 applies the pilot-to-program criteria so the Commission and stakeholders can assess the activities which PGE recommends as necessary to move our 2016 IRP DR resource activity into a stable, long-term, and cost effective program.

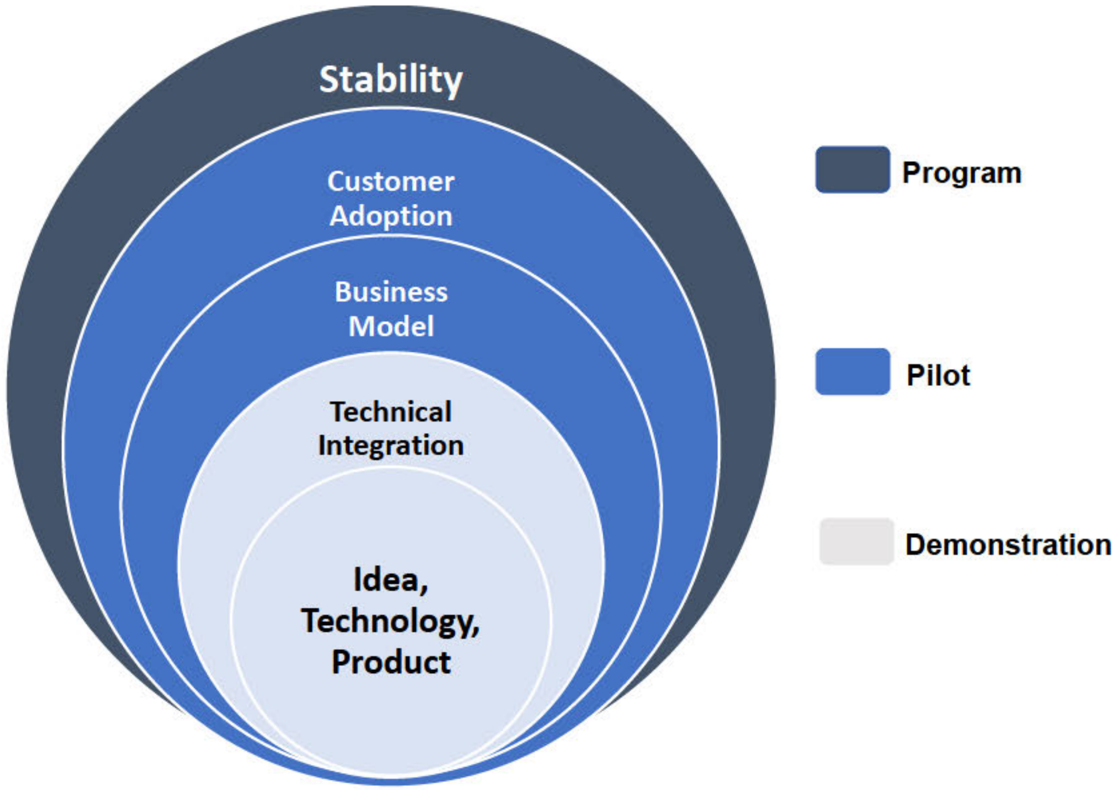


Figure 6 – Program Evolution

Learnings from demonstrations and pilots must inform the decision whether to deploy a product or service at scale. PGE's Product Lifecyle Management (PLM) process is the funnel through which potential ideas and products must travel on the way to program status. PLM provides the key questions to answer, the deliverables, the decision-making criteria, timelines for evaluation, and other protocols necessary to manage the rollout of a full-scale offering. By creating a funnel that enables PGE to test more ideas, products, and technology, promising projects are able to mature and reach full-scale deployment, while poor concepts are discarded early with less wasted effort and resources. This deliberate process for product advancement allows PGE to create compelling and cost-effective solutions for customers that align with our goals of serving load, reducing carbon, and maintaining reliability.

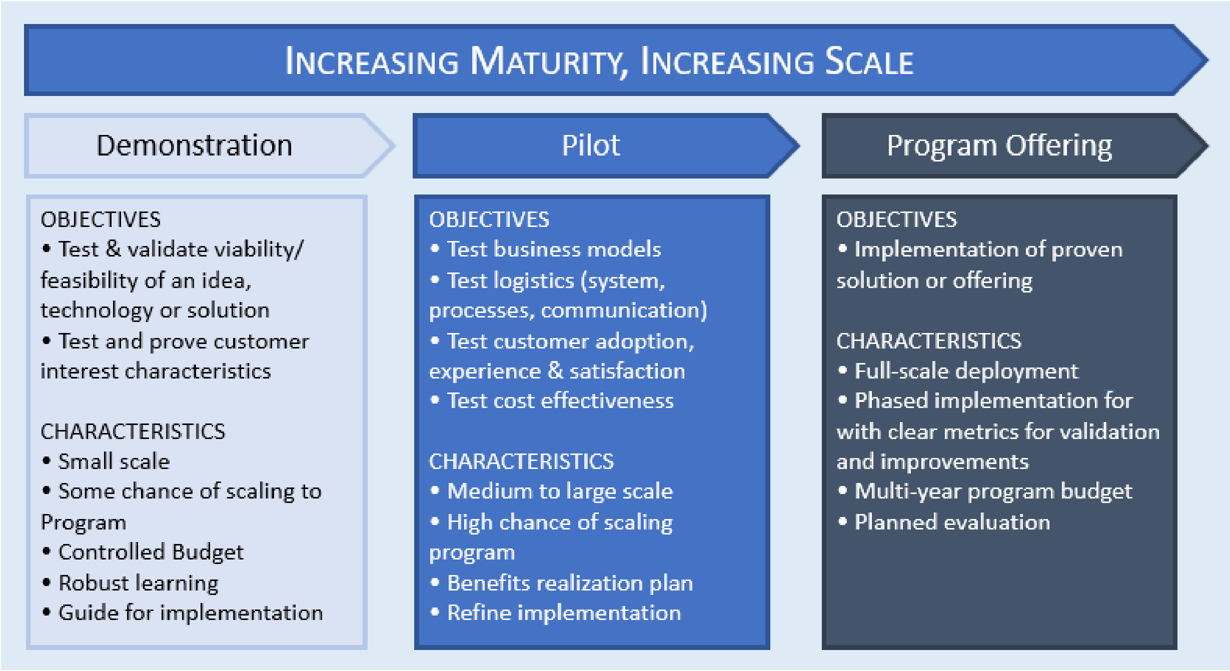


Figure 7 – Evolution Path in the Demonstration-to-Pilot-to-Program Lifecycle

Figure 6 shows that as products move through the pipeline, the probability that they will scale into full market deployment increases. Products with little chance for scaling should fall out of the pipeline quickly. Products that do not advance in the pipeline are not failures; rather they are opportunities to capture and incorporate lessons learned to inform future efforts.

2.4 Proposed Approach to Pilot to Program

For a flexible load resource to reach maturity, it must be aligned with, and integrated into, PGE's real time operations. While current Commission Orders require that PGE dispatch DR pilots from the Program Management department in order to meet learning and utilization objectives[51], PGE is working to assure that each DR resource developed as part of the 2016 IRP DR build can be aligned with our grid operations and has a path to dispatch integration. PGE's Program Management is working closely with Power Operations and the Balancing Authority to identify how best to integrate flexible load activities into real time operations so the resource can be utilized as any other resource in PGE's supply stack.

Unlike traditional generation resources, flexible load resources are customer-based, with operating parameters that are still being defined. These new, customer-based resources require PGE's system planners and grid operators to think differently about how aggregated distribution resources should be valued, developed, and dispatched to meet electricity demand on an hourly, sub-hourly, or resource adequacy basis. Likewise, if Power Operations makes a decision to dispatch DR, it needs certainty that the resource will perform at the expected level. PGE must be able to centrally dispatch DR on a resource and system level. Consequently, PGE now views the integration of the DR resource into real time operations as a necessary factor in determining whether a DR pilot has matured to a program.

The pilot-to-program offering criteria outlined below were gained through numerous learnings in the context of an accelerated resource build with a high degree of risk. Consequently, many of the Company's DR customer offerings have remained in pilot phase. PGE sees five key interrelated considerations for the transition from pilot to program offering:

1. Customer Experience
2. Program Parameter and Infrastructure Stability
3. Grid Performance
4. Financial Performance
5. Dispatch Integration

2.4.1 *Customer Experience*

Each DR and flexible load program must achieve a stable and sustainable customer participation level based on the learnings of the pilot coupled with effective recruitment and retainment practices. Pilot learnings identify the keys to customer satisfaction and ensure that participating customers have a solid understanding of their commitment and their reward for providing service when requested.

[51] Commission Orders in dockets UM 1514 and UM 1708 required PGE to dispatch DR pilots multiple times per year to ensure PGE not only builds the capacity, but also learns about and utilizes the resource. However, this requirement to dispatch the resource outside of economic dispatch parameters meant that each pilot must be dispatched, not from the Power Operations department, but from the Customer Programs department.

PGE must measure and understand participant satisfaction and look for ways to sustain, if not improve, performance.

2.4.2 *Program Parameters and Infrastructure Stability*

Each DR and flexible load program must have: 1) stable parameters as specified in an approved operating tariff; 2) stable and mature technology to provide the necessary infrastructure; and 3) stable operating processes that are well understood by participating customers.

2.4.3 *Grid Performance*

Grid performance and monitoring is essential to unlock the value from co-optimizing flexible load across capacity and grid services, as well as capturing locational value. As flexible load is capable of providing more grid services and PGE's implementation of ADMS enables locational dispatch, PGE will be able to dispatch Virtual Power Plant resources at the substation level. This granularity is necessary for capturing locational value and for ensuring flexible load resources are operating within the physical limits of the substation and distribution equipment behind which they are located.

To meet grid performance requirements, PGE must understand both aggregate event performance as well as hourly and sub-hourly dispatch performance for both planning and operational purposes. For DR and flexible load programs providing sub-hour grid services, PGE will need to be able to monitor the performance of the aggregate resource in real time in order to document compliance with reliability standards.

2.4.4 *Financial Performance*

That each DR and flexible load program (or a combined portfolio of multiple products) is cost effective. Additionally, each program must have an approved mechanism for cost recovery. A more detailed discussion of cost effectiveness is addressed in Chapter 3.

2.4.5 *Dispatch Integration*

PGE must establish DR and flexible load program dispatch protocols from integration and use by real-time operations. Programs must integrate not only with PGE optimization and dispatch systems, but also with the Western EIM. While DR can be accommodated in the EIM through exogenous communications[52], to fully capture the full value of DR in the EIM, PGE's goal is to ultimately include DR and flexible load programs within the EIM optimization. operators. This means that each flexible load resource will need a 'master file' whereby the generation

[52] Phone calls or email, for example.

optimization tool[53] knows the resource by its operational capability and constraints. In addition, each DR and flexible load program must perform within a 15-20% variable tolerance in order to be considered reliable enough for dispatch integration. This means that when PGE calls for capacity from such a program, we can predict, within a 15-20% error band, the amount of grid services that will be provided by the resource. It also means that the nominated load for each pilot or program must perform well enough so that Power Operations considers the resource viable for utilization.

PGE is actively working to include the Energy Partner program - the most mature program in the PGE DR/flexible load portfolio - into PGE's generation optimization tool with a master file. Energy Partner will be the first of our DR programs mature enough to attempt this integration. The goal of the Energy Partner program is to provide 27MW of peak capacity by end of year 2020. Program Management is currently working with Power Operations to incorporate Energy Partner into existing dispatch practices, such that Energy Partner is seen agnostically, as a resource within the resource stack, and dispatched based on its operating profile. The process for this integration has started. Figure 8 maps our current Energy Partner dispatch practices and protocols.

[53] PGE uses ABB Ability Portfolio Optimization tool to provide a generation schedule for energy and ancillary services, fuel nominations, and support the development of Base Schedules for the Energy Imbalance Market. This tool has the capability to optimize a combined portfolio of supply resources (traditional generation) and demand response/ distributed generation assets modelled as Virtual Power Plants.

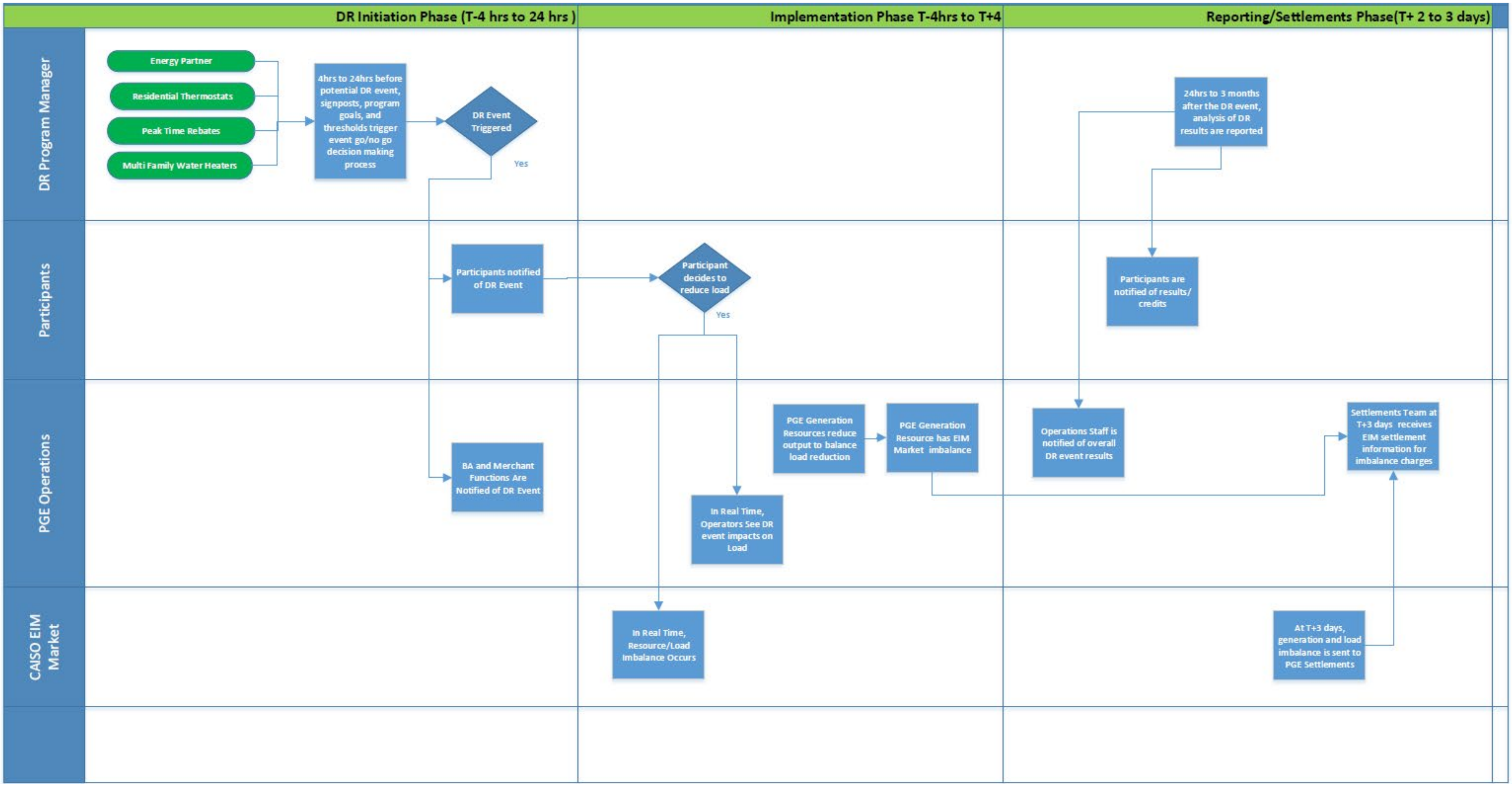


Figure 8 – Current State Process for Demand Response Program Operational Integration

The most immediate takeaways from Figure 8 are:

- The full integration of Energy Partner into real time operations will require process changes in Power Operations, the Balancing Authority, the Customer Programs Team, and Energy Partner itself. This will include communications to the participants about the change and how it may, or may not, affect them and their expectations.

PGE has been working cross functionally with the Customer Programs, Power Operations, and Balancing Authority teams to develop an approach to flexible load dispatch. Using the processes outlined in Figure 8, as the current state, Figure 9 was developed to show necessary process changes.

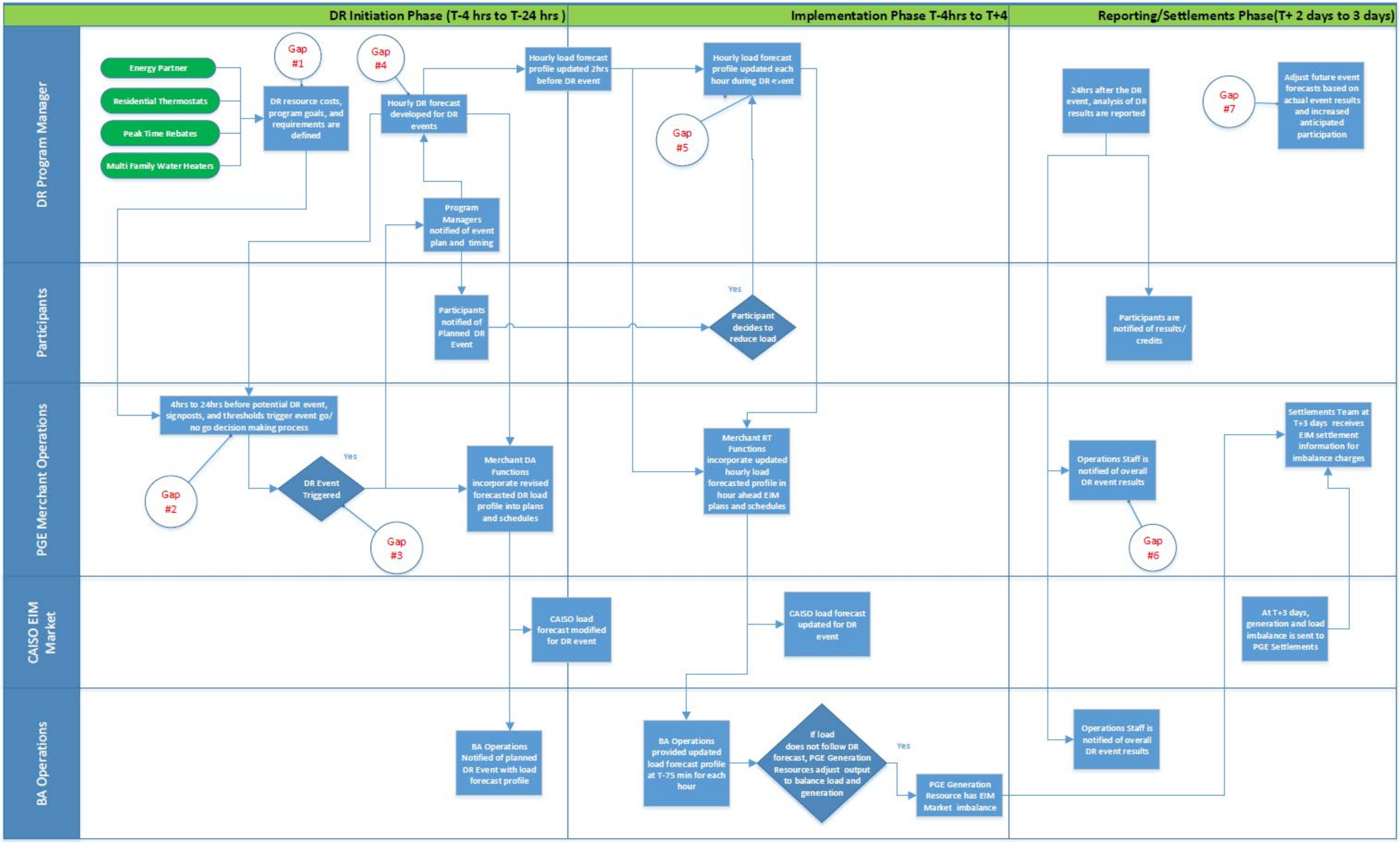


Figure 9 – Future State Process for Demand Response Program Operational Integration

Figure 9 is meant to guide PGE's work to place flexible load into real time operations activities to be operated as any other resource and dispatched to meet economic and grid reliability needs. The figure identifies seven areas for improvement and recommendations for action:

Gap 1. DR program operations parameters need better definition, clarity and visibility.

Recommendation: DR Program Managers define overall program costs, incremental dispatch cost, must run requirements, other program goals, and sign-posts important to the economic dispatch trigger process.

Gap 2. The DR event trigger process should be better defined for economic dispatch and the "go/no go" decision-making process should lie with Power Operations.

Recommendation: DR Program Managers and Operations Leads partner to define the economic dispatch signposts and thresholds that will be used to trigger DR event "go/no go" decision-making process.

Gap 3. The final decision to trigger a DR event for economic dispatch should be made by Power Operations using the appropriate parameters, thresholds, and sign-posts.

Recommendation: Power Operations partners with DR Program Managers to stand up decision-making process for economic dispatch of DR event.

Gap 4. DR load reduction hourly forecasts for each event are not part of the current process.

Recommendation: DR Program Managers develop a process for providing hourly DR forecasts for the entire event duration of planned and future DR events.

Gap 5. DR event load reduction real time monitoring is not part of current process.

Recommendation: DR Program Managers develop a process for gathering real time information on actual load reduction and provide updated forecast for remaining duration of the event.

Gap 6. A "Post DR Event Results Summary" is needed to provide program managers and operations staff updated information for settlements analysis and next event planning.

Recommendation: DR Program Managers develop a process for providing a complete "DR Event Results Summary" a maximum of 48 hours after the conclusion of the event.

Gap 7. Past event results and changing customer participation should be used to modify DR Program parameters and forecasts to enhance the future DR event trigger process.

> **Recommendation:** DR Program Managers to develop a process for updating key DR parameters for future program enhancement.

PGE will also adopt the following structure and review consideration for pilots and programs as outlined by Commission Staff in October 2020.

2.4.6 Pilot and Program Investigation and Proposal Components and Criteria

2.4.6.1 Pilot Review Considerations

When reviewing pilot proposals, PGE will address with following queries:

1. Is this research valid and valuable for the ratepayer?
    a. How does this new research fit into existing services and other ongoing research?
    b. Is this new research, or has it been conducted already?
    c. Does this pilot have the potential to result in wider adoption?
2. Will this research result in the desired information?
    a. Will this research provide the information needed to answer the research question?
    b. Is the pilot structured such that it will further the intended policy objective?
    c. At the end of this research, the pilot will: i) end, ii) be redesigned as a new pilot, or iii) transition into wider adoption (through a program, upgrade or other). Will this research lead to this decision point?
3. Will this research be conducted in a way that limits the risk to the ratepayer? Including:
    a. A scope with a clearly stated research question.
    b. A statistically sufficient population of units to perform the research.
    c. A duration that is limited, but sufficient to conduct the research and evaluation.
    d. A budget of appropriate size.

Overall, the purpose of these questions is to reduce risk to ratepayers while allowing the utility to test a concept in a pilot framework.

2.4.6.2 Pilot Proposal Components

PGE will submit the following items with each pilot proposal:

1. The purpose of the research (including, if applicable, which legislative or Commission order it supports, and how it supports the implementation of the directives contained therein).
2. The research question.
3. The overall pilot design strategy: What is the theory behind this strategy? The major design components should address the research question.
4. The potential benefits to the ratepayer if the pilot succeeds.
    a. Portfolio consideration: A description of how this pilot complements or adds to related utility activities and addresses a market gap/opportunity not currently addressed by current operations or ongoing research, and how overlap with existing work is minimized.
    b. In support of EO 20-04: Will there be any positive or negative impact in reducing GHG emissions as a direct result of this pilot, or if applied to wider adoption?

   c. In support of EO 20-04: Will there be any positive or negative impact on any "vulnerable populations or impacted communities" as a direct result of this pilot, or if applied to wider adoption?
5. Context: Prior research and relevant market research supporting this strategy. What are the major barriers that stand between this concept and wider adoption? What is the technical/conceptual viability of what is being tested, i.e. how market-ready is it? Has this been implemented elsewhere?
6. A research plan that includes:
   a. The learning objectives that will inform the research question(s) and how these objectives will be achieved.
   b. Participation target: Who, or what, will this pilot target?
   c. Potential scale: what is the ultimate potential?
   d. Number of participants or test subjects: include statistical rationale for this number.
   e. Evaluation strategy: A description of how the evaluation will be conducted. How will we know if it worked? The evaluation plan should answer whether or not the idea should be rolled out for broader adoption. Include what is necessary to measure results at the needed level of statistical certainty.
7. Schedule: A timeline that shows when each component of the plan will be implemented. The duration of the pilot must be limited, yet sufficient to answer the question. The schedule should include time for conducting the evaluation, final reporting, and any necessary activities to wind down the research.
8. Budget: What will this cost? The budget should be sufficient to answer the question and limited in scope and costs to reduce risk to the ratepayer. Budget should include O&M expenses and revenues, broken down by FERC account, capital costs, number of FTE employees, and number of contractors.
9. Decision points: Built-in milestones or dates where the pilot is evaluated against project objectives to determine if the pilot requires a change in scope or should end early.
10. Reporting requirements: The proposed cadence of utility reporting on progress and results. This may include GHG emissions reductions if applicable.

2.4.7 Transition

To aid in Commission Staff's oversight role, PGE will provide the Commission the appropriate information when proposing a pilot-to-program transition. This will include well-structured evaluation to aid Staff in their validation of pilot performance, including an assessment of readiness to transition from pilot to program, or whether to end the pilot or reformulate it into a new pilot.

2.4.7.1 Transition Review Considerations

When a pilot comes to an end, PGE will provide Commission Staff the necessary information to address the following consideration:

1. Was the pilot run successfully? Were the research objectives accomplished and did the pilot answer the research question? If the pilot was successful, Staff can review results prior to transition from pilot-to-program; if the pilot was not successful, the concept may be worth revisiting in a new pilot, or it may be best to cease research on the topic.

2. Did the results of the pilot indicate that the idea is worth adopting? The evaluation results will play a key role in Staff's assessment. If there are positive results with quantifiable ratepayer benefits, this indicates that the concept is worth pursuing for the goal of broader adoption.
3. Did new, pressing questions or obstacles arise as a result of this research? If a significant barrier is identified, there may be a benefit in running another pilot or some other form of research to prepare for rollout. If no new, serious challenges arise, it is time to plan for transition into wider implementation, whether that be as a program, or other form of implementation.

If it is determined that the pilot should transition into wider adoption, Staff may work with the utility on a transition plan to apply learnings from the pilot in a timely and effective manner.

PGE agree with Staff that applying a framework to review pilot results will help roll out beneficial ideas more quickly, so that the risks taken on by ratepayers will turn into benefits sooner and be shared with ratepayers.

Chapter 3 Programs

3.1 Program Review Considerations

Programs are expected to provide benefits to ratepayers for an extended duration with relatively stable costs and benefits, with the understanding that there may be a predictable band of fluctuation in productivity. As a sustained offering, program proposals will provide information to assess the following considerations:

1. Predictable outcomes.
2. Discrete offerings.
3. A repeatable process to deliver the program offering.
4. Just and reasonable rates.
5. Measurable benefits.
6. Ongoing implementation.
7. Periodic evaluations.

Staff understands that there will be more fluctuations and learning in the early stages of a program, which makes the above considerations important in creating a stable, lasting offering.

3.2 Program Proposal Components

Key components to a program proposal include:

1. The purpose of the program (including, if applicable, which legislative or Commission order it supports, and how it supports the implementation of the directives contained therein).
2. Program goals.
3. Expected benefit to the ratepayer.
    a. Portfolio consideration: a description of how this program complements or adds to related utility activities and addresses a market gap/opportunity not currently

b. In support of EO 20-04: Will there be any positive or negative environmental or carbon impact?
c. In support of EO 20-04: Will there be any positive or negative impact on any "vulnerable populations or impacted communities"?

addressed by current operations or ongoing research, and how overlap with existing work is minimized.

4. The overall design strategy: What is the theory behind this strategy? How is this going to work? The major design components should lead to the program's goals.
5. Prior research and market research that supports this strategy (including learnings from past pilots if applicable).
6. Participation target: Who, or what, will this program target?
7. Potential scale, and other relevant market research.
8. Schedule: A timeline that shows when each component of the plan will be implemented.
9. Budget: What will this cost? Budget should include expenses and revenues, costs by FERC account, FTE of employees and of contractors, and any anticipated capital costs.
10. Reporting requirements: The proposed cadence of utility reporting on progress and results. This may include GHG emissions reductions if applicable.
11. Evaluation plan: This plan includes what will be measured, how it will be measured, and how the results will be verified. This evaluation is typically conducted by a third-party unless the utility has a persuasive reason to conduct it in-house.

3.2.1 Follow-Up

PGE will work with Commission Staff when questions arise on the process and guidance presented herein. PGE will continue to meet with Staff and other interested parties to discuss process and its potential impact on current work.

3.3 Moving to a Portfolio Level Development and Deployment

Designing to Scale	Design demonstrations and pilots to maximize learning and prepare for full scale deployment

Current practices require that PGE file a proposal for each product offering, channel, and program expansion. Although this process was adequate in the past with few pilots, it is proving to be inefficient, resulting in long deployment timelines and a Piece-meal approach to budgeting.

In adopting the Product Life Cycle Management process, PGE shifted its focus from individual program launches to portfolio optimization. Our portfolio roadmap outlines market approaches and strategies to capture increased DR capacity through least cost channels.

PGE has identified two focus areas and four strategies for portfolio optimization. Figure 10 shows the high-level focus area and strategy. Greater detail is provided in subsequent sections.

Focus	Building Flexibility & Transportation Electrification	Ensure buildings (homes and businesses) & electric vehicle charging infrastructure is flexible, efficient, and automated
	Virtual Power Plant	Integrate and manage resources to improve system-wide flexibility and optimization.
Strategy	Customer Engagement	Engage customer to actively decarbonize our region to understand their priorities
	Products & Services	Meet customer needs in homes, businesses, and campus/communities
	Engagement to Build & Leverage Partnership	Engage and lead partners to create an flexible ecosystem
	Policy & Regulatory Evolution	Engage with policy makers and regulators to assure understanding of investment strategy and deployment approach

Figure 10 – Areas of Focus and Strategic Approaches

Flexible, efficient, and automated solutions enable portfolio optimization across multiple grid services. Portfolio automation and optimization allows for the stacking of solutions and cost sharing that enable programs to be cost effective. Cost effective programs are attractive to customers and enable PGE and its customers to choose holistic solutions to decarbonize the electric grid at least cost. PGE is addressing these areas of focus with four strategies:

1. A focus on **customer engagement**, which is centered around identifying customer-centric solutions that empower customers to decarbonize and electrify, while controlling costs. As noted above, PGE's Testbed includes numerous research efforts that target customer engagement, identify customer preferences, and address energy system inequities.

2. PGE is **providing products and services** that meet the needs of homes, businesses, and communities. PGE is using customer and performance feedback identified through the demonstration-to-pilot-to-program lifecycle to adapt product offerings to meet customer and operational needs.

3. PGE is actively **building and leveraging key partnerships**, such as municipal partnerships to provide decarbonized, flexible solutions to actively shape local ecosystems. This is accomplished via important rules and regulations such as zoning and building permitting.

4. PGE recognizes that it cannot be as effective and efficient in supporting its customers in their drive for connected, flexible, and decarbonized load without **policy and regulatory evolution** that specifically allows for PGE to actively engage in building flexible load behind the meter.

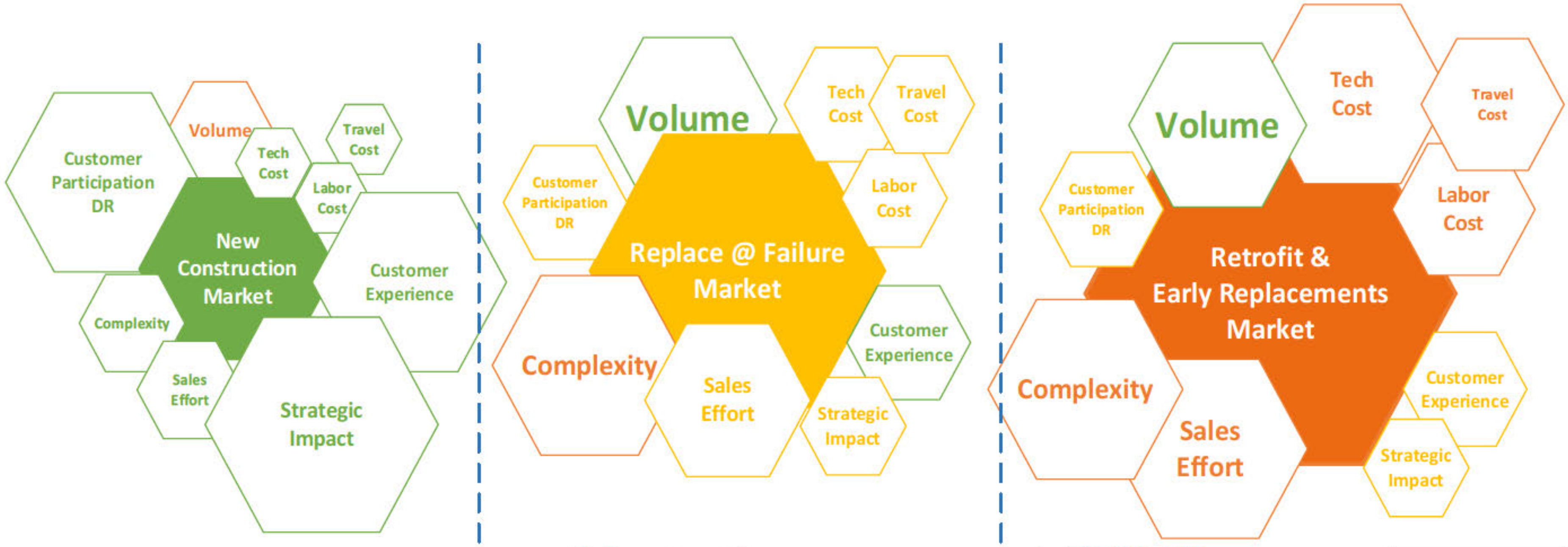
3.3.1 Market Organization – Effective Deployments of Products and Services

The first focus area is building a Virtual Power Plant, as described above (Chapter 1), and interwoven, below.

The second area of focus is building flexible load within the built environment and within transportation electrification infrastructure. This work looks to ensure that buildings (homes and businesses) and electric vehicle charging infrastructure are enabled to provide flexible services to the grid. The goal is to create a built environment and electric vehicle infrastructure capable of being incorporated into real time operations by PGE through resource integration and distribution system planning activities. PGE discusses our approach to distribution system planning in later in this chapter.

If the proposal to move to multiyear strategic planning and budgeting is approved PGE will more easily move to portfolio level planning. PGE first demonstrated portfolio level planning with our 2019 Transportation Electrification Plan.[54] This will allow us to not only plan for related expenditures across a series of activities it will also enable us to work across market opportunities. Presently PGE's demand response activity is more focused on the retrofit and early replacement market. However, if PGE were to bundle our activities, we could leverage strategic endeavors to assure new home builders install a pre-provisioned smart thermostat. The installation of this thermostat would come at a lower price creating opportunity for PGE to reach more customers across the replacement and retrofit market while maintaining and overall cost-effective approach to a smart thermostat program. By applying a portfolio lens to our market approach, PGE is able to stack offers and solutions and to spread overall program overhead costs.

[54] Portland General Electric, 2019 Transportation Electrification Plan, OPUC Docket UM 2033, Available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=haa102039.pdf&DocketID=22127&numSequence=1



- Lowest cost – wholesale prices
- Limited market Size
- Opt-Out Design resulting in high participation
- Volume Sales
- Cost savings due to DR-ready products & scaled installations
- Sets expectations for all homes: new & existing
- Flip Entire Projects
- Products Delivered Seamlessly to Future Occupants

- Medium costs – retail prices
- Large market
- Opt-In design resulting in ~20-30% participation
- One-off Sales
- Cost Savings Due to DR-ready products
- Contractor already on site
- Reliant on trade allies
- More complex to delivery bundled products + experience
- Naturally occurring sales

- High costs – retail prices
- Expensive DR + communications equipment
- Expensive labor costs
- Expensive travel costs
- Adoption hurdle due to remaining value of existing equipment – limited customer shared cost structures
- Large market
- One-off Sales
- Consumer marketing required

Legend
Good
OK
Bad

Figure 11 – Working Across Market to Bundle Customer Offerings

Figure 11 depicts three different opportunities for product and equipment solutions to be deployed to customers. The surrounding hexagons represent characteristics of that opportunity. The size of the hexagons refers to their relative importance and market size. Green hexagons denote generally good and unproblematic characteristics presented by that opportunity, whereas yellow hexagons depict more challenging situations that can be overcome. Orange hexagons are complicated, costly situations and environments. The following provide additional detail on each opportunity:

- *New construction focus.* There is considerable benefit to working in the new construction market. The builder, developer, and owner/tenant must purchase equipment to operate the building and pay for installation, creating an opportunity for PGE to influence this decision. There is a relatively small difference in cost between inefficient, inflexible equipment and efficient, "smart" equipment. The approach reduces costs for program implementation as it mitigates high long-term costs of retrofitting so-called "dumb" equipment. This is also the time when close to 100% of the potential load can be captured, because EE and DR incentives can be offered to lower customers' initial capital investment in exchange for ongoing participation in the Virtual Power Plant. Additionally, capturing the new construction market has a strategic impact, as the existing building market takes cues from new construction regarding the standard practices for remodeled, modernized building. The downside to this market is that it is relatively small. Electric Vehicle Service Equipment (EVSE) is a natural fit here.
- *Replace upon failure.* The replace upon failure market takes advantage of existing equipment naturally failing over time. This provides an opportunity for program incentives to pay the incremental costs for "smart" equipment. This program approach pays very little, if any, for installing the product. The challenge in capturing this market is that there is a very short window of influence between the time of equipment failure and the customer's replacement decision. It is necessary to cultivate a deep trade ally network that already engages with the customer. Additionally, it is difficult to deploy product bundles (multiple products) in an integrated fashion because trade allies usually specialize to a product line or a product line within a particular appliance in one product type. Finally, the structure of this market poses challenges for providing a consistent, high quality customer experience. However, the addressable market is multiple times the size of the new construction market and offers promise for driving volume.
- *Retrofit and early replacement.* The retrofit and early replacement market is dominant in driving the volume of flexible load resources today. The upside is the volume of products that can either be retrofitted or replaced early; the downside is that very few customers will cover the cost to retire functioning equipment early or to upgrade/retrofit existing equipment. The cost of retrofitting unconnected equipment is usually cost prohibitive from both a program and a customer perspective. However, the size of this market makes

strategic investments a key part of accelerating the development of flexible load into the Virtual Power Plant.

3.3.2 Product Bundling

PGE is moving from a product-by-product approach towards bundling products for delivery in each target market. To enable the full value of bundling, PGE will be exploring new ways of capturing the full value of a flexible home. This is a critical step in making it cost effective to invest in equipment upgrades that allow all customers to participate. The result is a much higher density in program participation right from the start. For example, in the near future water heaters will be pre-built with demand response enablement. Similarly, EVSE will demand response capable. These two home loads can be bundled and offered at the value of the service provided. An additional approach to bundling is where a thermostat can be offered at the same time as the new water heater is installed. This approach helps PGE and by relation the Energy Trust lower deployment costs.

A core bundle is to target the single-family new construction market. Such an approach revolves around taking existing (or soon to be launched products) and adapting the entire product bundle for implementation by builders and developers. This approach allows for close to 100% of new homes to be grid-enabled, connected, and participating in grid services by the time the new homeowner moves in.

Stand-alone programs targeting existing technology in customer homes can only capture approximately 25% of the connected load. Bundling allows individual products to share delivery infrastructure and drives down the relative cost-per-acquired flexible load device for the Virtual Power Plant. This creates a virtuous cycle where more devices get connected, economies of scale are realized, and technology matures, which in turn drives down equipment costs.

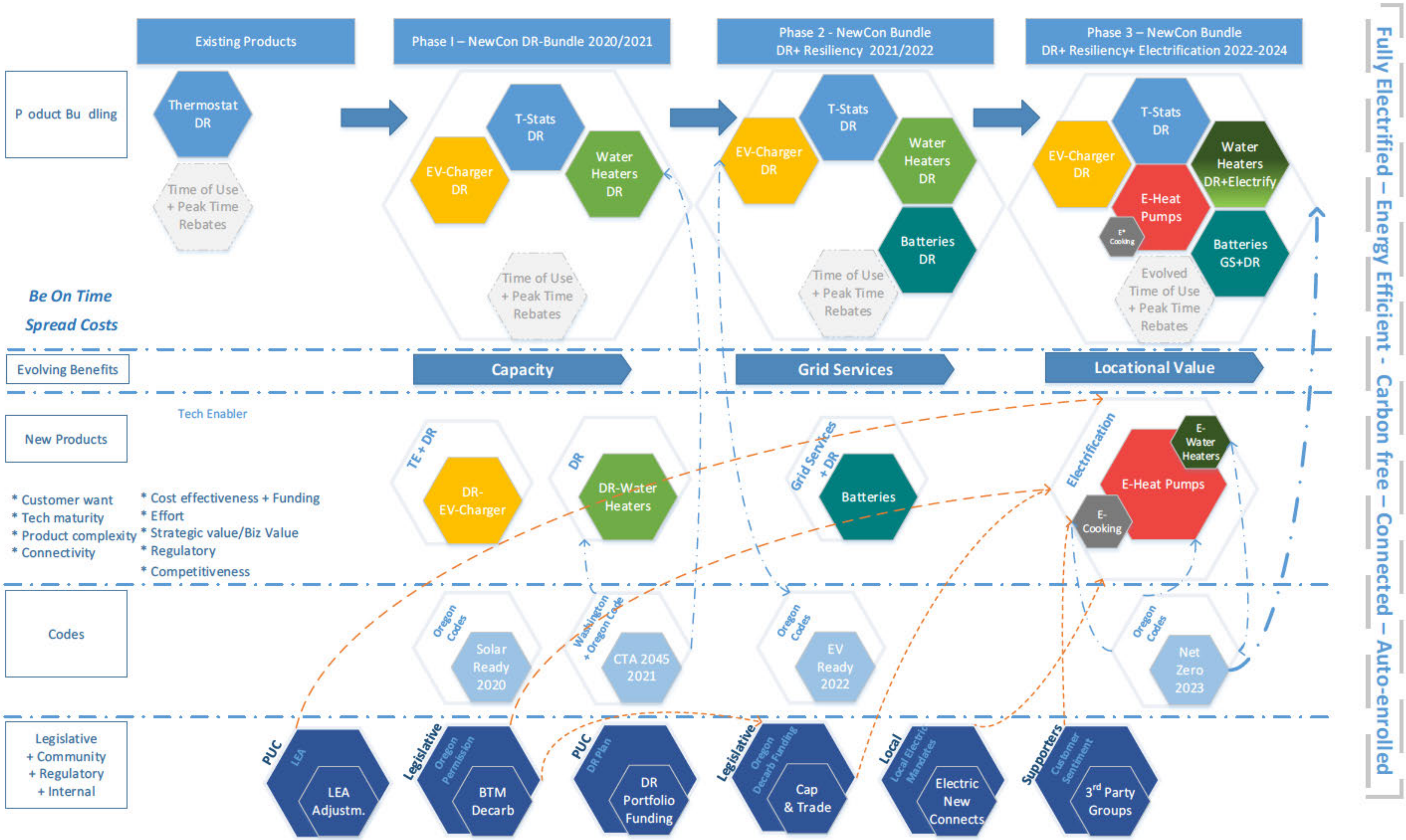


Figure 12 – Evolution of New Construction Bundles

3.3.2.1 Cross-Marketing

It is important to recognize that PGE's approach will require us to take advantage of naturally occurring every-day sales and installations by retailers, manufacturers, homeowners, or contractors. Similarly, each product still requires its cycle of testing, learning how to manage the load, and the successful delivery of DR events and seasons. This provides critical mass to answer questions in the demonstration and pilot stages of specific programs. However, the medium-term vision is to drive down the costs of each product solution by cross-marketing and cross-delivering the products via bundles, which yields greater program participation.

3.3.2.2 Code Evolution

Leveraging the universal application of codes and standards to enable grid connectivity of flexible load could lead to rapid growth in Virtual Power Plants while significantly reducing costs. Today, codes and standards primarily target EE or renewable energy development; expanding codes and standards to enable grid connectivity would significantly simplify the program development process. Building and appliance codes make or break the cost-effectiveness of product solutions. Codes can set up a home or appliance to be decarbonized and grid-ready, thereby avoiding substantial retrofit costs, which could in turn negatively influence the success of products for decades to come. Setting standards that extend beyond the customary EE and renewable-focused codes towards minimum standards and requirements for grid-connectivity allows for much-reduced costs in building the Virtual Power Plant at a quicker pace.

On the bottom third of Figure 12 one can see the adjustments to codes and standards that could accelerate or support PGE's development of the flexible load resource.

3.3.2.3 Bundle Evolution

Figure 13 shows how new product development fits into bundles and how those bundles reach the retrofit, existing building and upgrade market in phases.

The retrofit market will continue to be addressed by designing stand-alone products that target specific end-uses. As these products mature, they will be bundled together into integrated product offerings. The delivery of bundles to this market will initially be more difficult and challenging, but will yield savings over time, enlarging the cost-effective reach of each individual product in the bundle.

With bundling, customers can be recruited to participate in multi-product solutions, reducing overall program administration and customer acquisition costs. Installing products as a coordinated bundle reduces labor costs and other associated expenses[55]. Additional cost savings can be achieved from using common or merged software systems for tracking, managing, and dispatching installed assets.

[55] For example, travel to the location of installation, registration of the product, and establishing communications with the device.

These approaches will require demonstration to pilot to program development. As our pilots mature into programs their challenges such as performance, communications and customer acceptance will be known and likely stable enough to be offered across the new construction, replacement and retrofit market. However, to assure that pilot approaches to single family water heaters are ready to be deployed within a bundle, PGE will undertake demonstrations, such as our single-family water heater demonstration in the Testbed. Similar demonstration efforts will be needed to address other novel challenges and research requirements as we prepare new technology to be included.

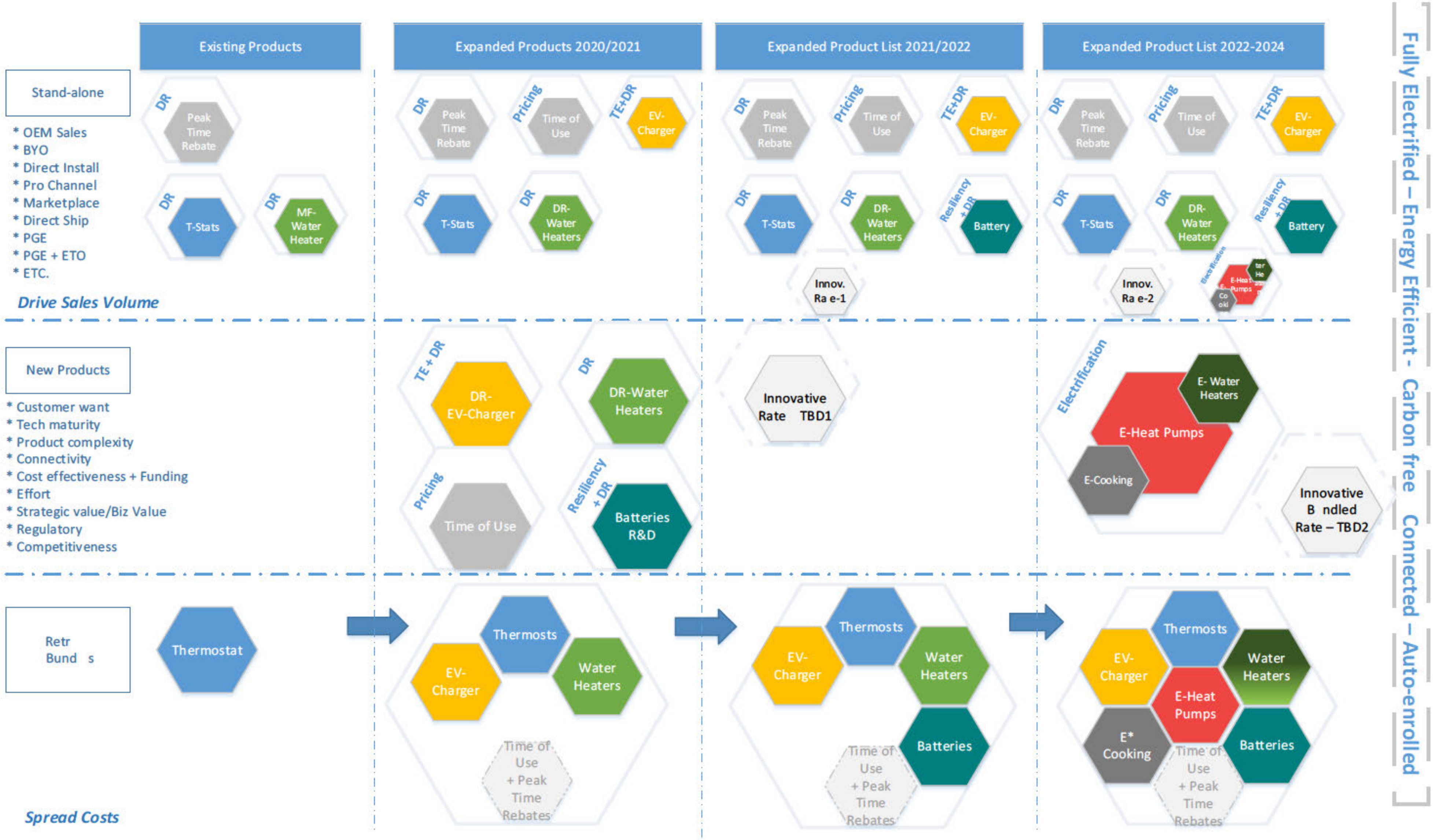


Figure 13 – BUILDINGS – Single Family – Existing Construction - Retrofit + Replace + Upgrade at System Failure – 5-year Roadmap

3.3.2.4 Products for Multifamily Home New Construction and Retrofit

The multifamily home market offers a unique opportunity to capture multiple flexible load devices at a single location; however, reaching this market requires addressing unique challenges and barriers. Figure 14 shows the products PGE intends to include in the bundle for the multifamily home new construction and retrofit market. Figure 14 also provides a timeline of the product build, how the products are bundled, and when the products and bundles will reach the market.

As noted above, PGE's first offering tailored to this market is the multifamily water heater program. In 2020, PGE plans to add the business EV charging program as a program offering for the multifamily and business markets. PGE is also considering line voltage thermostats, which could offer high volumes of winter DR from electric baseboard heaters. However, this product will likely require a demonstration stage to explore ways to address expected barriers, including high installation costs.[56] For this product to become cost effective, flexible load and EE benefits should be bundled; this approach requires a partnership with the Energy Trust in order to incorporate EE incentives. PGE expects the bundle to expand by developing products that allow for the connection of ductless mini-splits into the Virtual Power Plant in later years.

[56] Controls for this product must be installed by a licensed electrician.

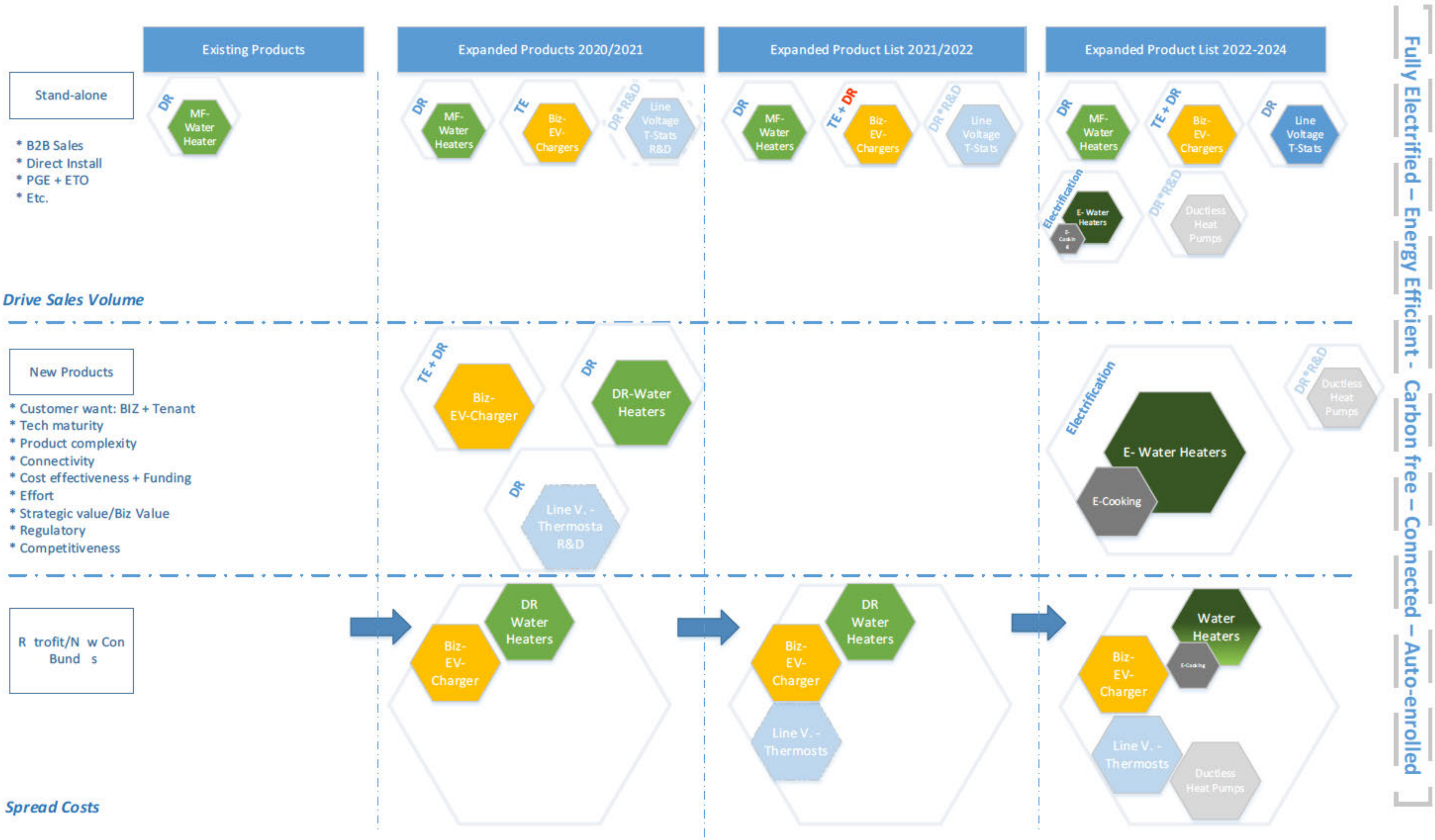


Figure 14 – BUILDINGS – Multifamily – New Con/Retrofit + Replace + Upgrade at System Failure – 5-year Roadmap

3.3.2.5 Products for Commercial Retrofit, Replace, and Upgrades

The Commercial Retrofit, Replace, and Upgrade market is another area in which PGE plans to expand flexible load program offerings and bundles. The commercial retrofit market includes grid-connected transportation, batteries, automated energy management, water heater, and HVAC controls. Figure 15 illustrates PGE's product roadmap for this market space and its channels.

One important mechanism in this market is the ability for PGE to offer grid-service participation incentives to encourage the customer to install efficient automated equipment that integrates with the Virtual Power Plant. The customer benefits though efficiency gains and better performing equipment, while PGE secures the right to operate the equipment to provide grid services.

Today, PGE's sole product in this space is the Energy Partner program. In 2020, PGE plans to add the business EV charging program to this sector as well. Additionally, new opportunities are arising for PGE to offer our customers resiliency offerings via flexible load strategies and technologies. With the help of PGE's Market Insights team, PGE's Portfolio Planning, Product Management and Development teams, is exploring other innovative program designs shaped by customer preference and values.

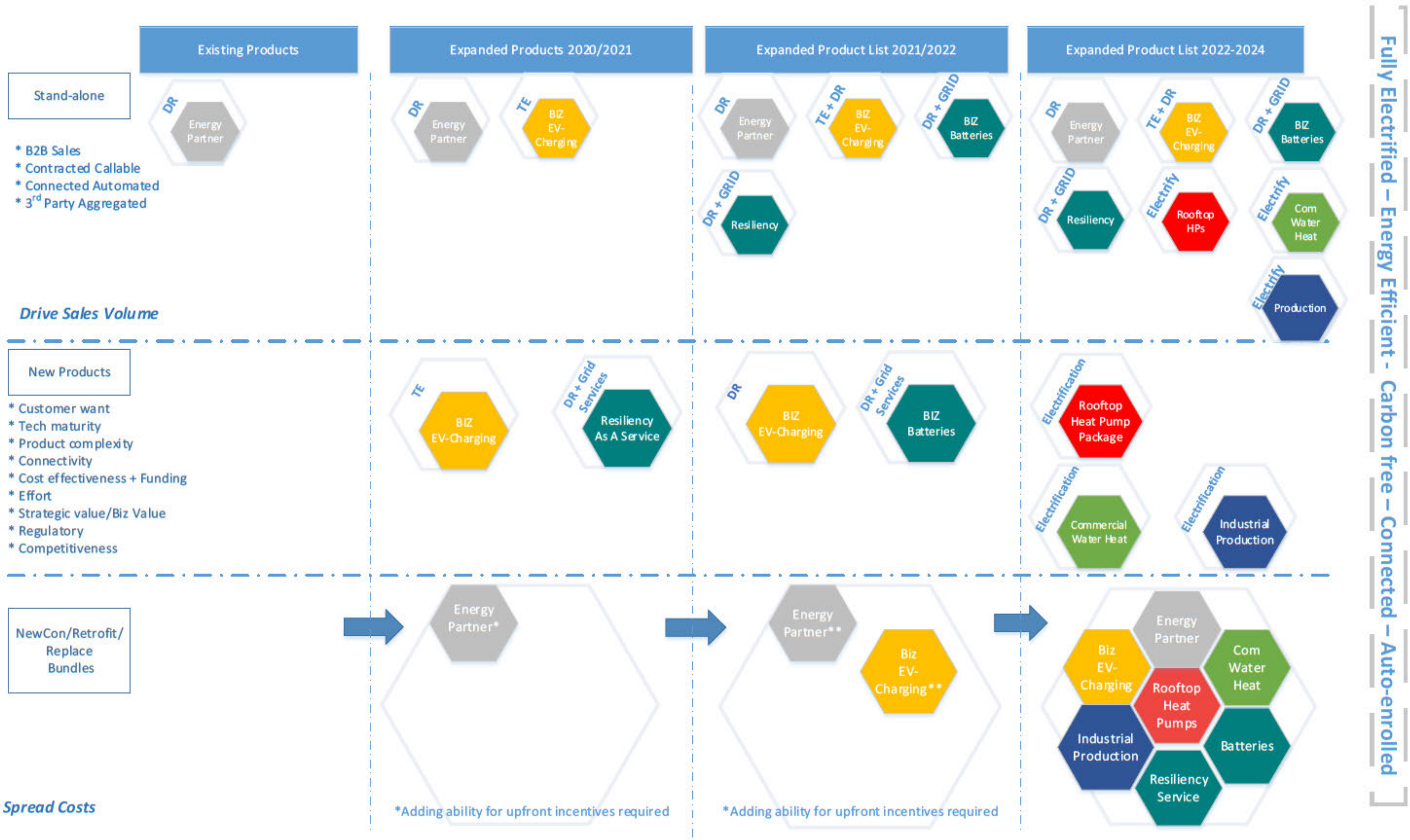


Figure 15 – BUILDINGS – Commercial – Retrofit + Replace + Upgrade at System Failure – 5-year Roadmap

3.3.2.6 District Energy Solutions

PGE is partnering with municipalities and governments to offer tailored services to large-scale planned communities. PGE refers to this sector as district energy. Reaching this sector requires unique program development and acquisition strategies that results in a more holistic implementation for larger projects and communities. This approach extracts product bundles from residential and C&I markets and applies them to large projects. Delivering district energy projects requires close coordination with external partners. PGE recognizes that, by offering builders and planners tailored solutions, our programs help meet the needs of the market to create large, well-coordinated flexible loads and help decarbonize the built environment. Figure 16 represents how the above items can be combined into a suite of products for a comprehensive district solution.

One recurring factor in current district energy projects is the desire to future-proof by providing enhanced resiliency specifically as it applies to critical infrastructure. PGE anticipates that many of these projects will include comprehensive energy supply and grid services agreements between PGE and the customer.

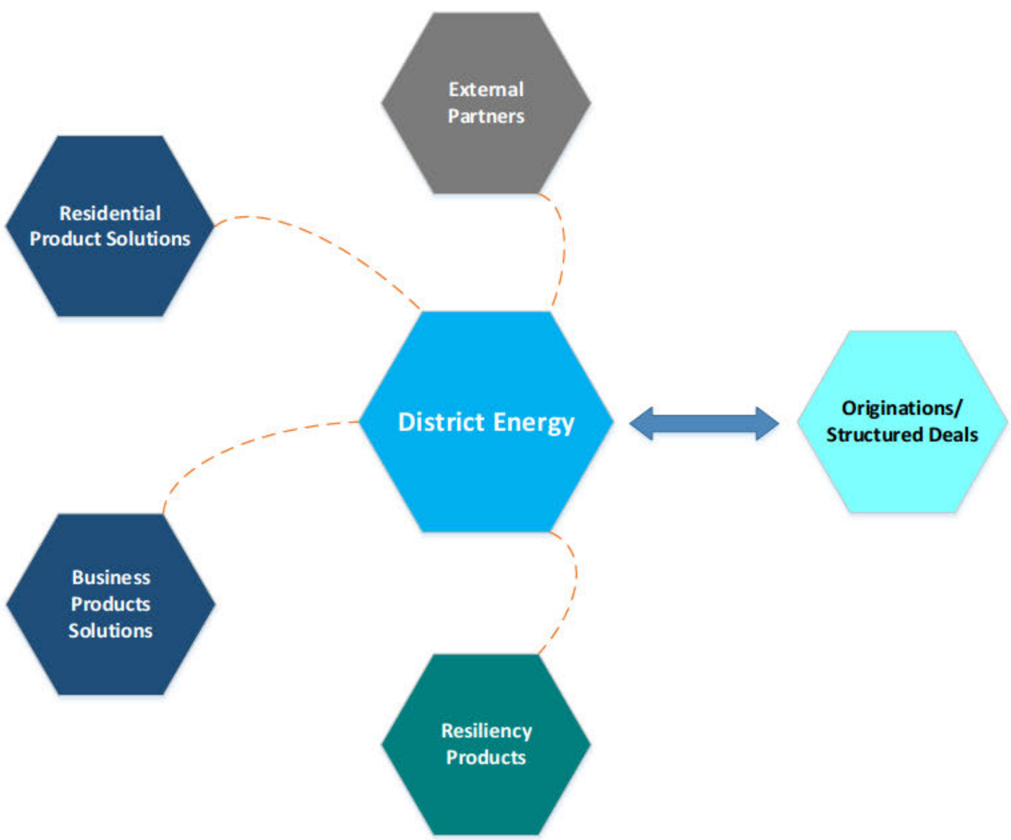


Figure 16 – Comprehensive Customized District Solutions – Perform, Decarbonize, Engage

District energy offers an opportunity to showcase how coordinated and intentional investments in large developments uses flexible load to enable the Virtual Power Plant. By employing applied systems thinking, PGE plans to engage with customers before and during the design of these projects to establish the optimal mix of resources and maximize value. Choosing the correct design, the proper equipment, and creating inter-connectivity between design elements allows for cost effective Virtual Power Plants that would be cost prohibitive in a retrofit scenario.

Stacking incentives from EE, DR, and auxiliary services with renewable resources allows costs to be driven down while driving momentum towards customer-centric, decarbonized, integrated solutions. A rare opportunity exists to create solutions where residential, commercial, and industrial solutions provide cross-sector benefits, creating a more robust and holistic grid interplay with the Virtual Power Plant.

3.4 Practices Proposal

This section contains PGE's proposal to the Commission to move to multiyear portfolio planning and budgeting. PGE asks the Commission to acknowledge the reasonableness of this practice change. This practice change would involve a subsequent filing to the Commission wherein PGE would delineate activity it would undertake to meet multiyear savings goals building to the 2025 savings goal adopted in the PGE 2019 IRP. This subsequent filing would include a budget proposal to reach the savings goals. The proposed practice outlined below also include regular reporting to the Commission and regular quarterly meeting with Commission Staff. The subsequent filing, tentatively referred to as a multiyear plan, would seek Commission approval. The multiyear plan would transparently communicate the activity to be undertaken, the milestones to be reached, and the dollars needed to meet savings goals. PGE's program staff has been open, transparent, and collaborative with Commission Staff, and will continue to work with Staff on the development of a multiyear plan.

Multiyear and Strategic Planning	Implement a long-term strategy for program development, cost control, transparency, and collaboration
Designing to Scale	Design demonstrations and pilots to maximize learnings and prepare for full scale deployment

Moving from demonstration to program requires that PGE implement a cohesive strategy for program development that maximizes technical, operational, and customer lessons learned. PGE proposes to efficiently and effectively acquire flexible load resources using a scalable and repeatable process.

As described in detail below, this will include PGE's 1) potential assessment and identification of multiyear flexible load acquisition goals through the IRP; 2) development of short- and long-term strategies to achieve identified goals; 3) budgeting; and 4) allocation of the necessary funding through a recovery mechanism similar to Schedule 109[57], or alternatively Schedule 135[58] [59]. PGE will implement its programs using demonstration projects, pilots, and programs. Finally, third-party evaluators will conduct program evaluations and PGE will share the results of those evaluations with the Commission and stakeholders. The high-level elements of this process are outlined in Figure 17.

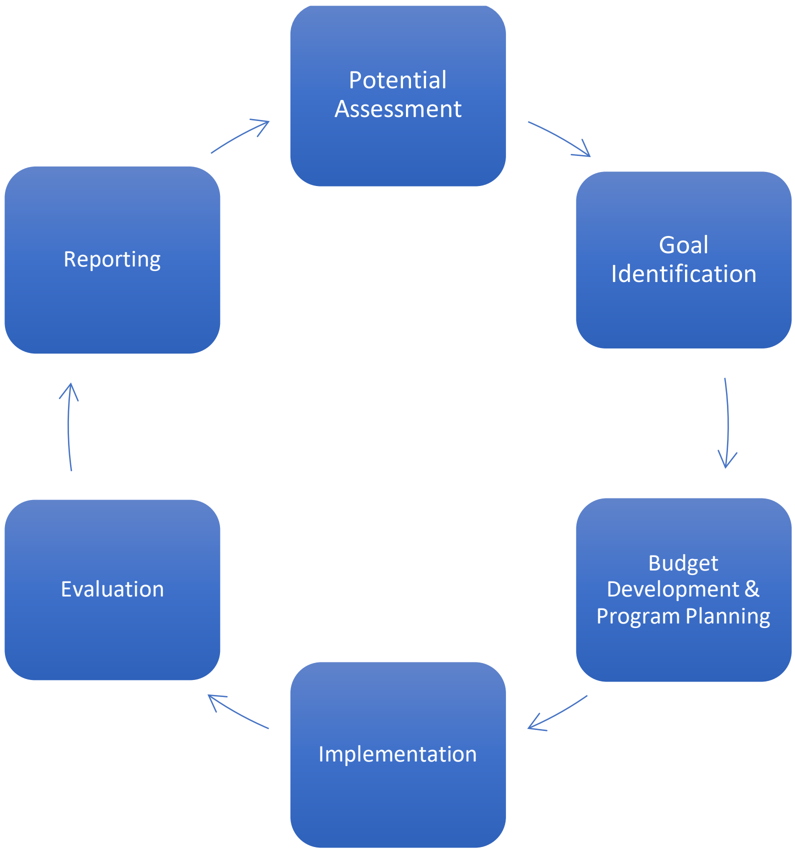


Figure 17 – Elements of PGE's Process to Acquire Flexible Load Resources

3.4.1 Goal Identification

PGE has a long history of planning for demand response and flexible load within the IRP. With each IRP, PGE refines and improves our planning practices and sets new overall goals for flexible load resources. However, the IRP does not set prescriptive, programmatic targets or detailed implementation plans. By grounding of PGE's flexible load goals in the IRP process, planning and

[57] Portland General Electric Schedule 109 Energy Efficiency Funding Adjustment, available at; https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_109.pdf.
[58] Portland General Electric Schedule 135 Demand Response Cost Recovery Mechanism, available at; https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_135.pdf.
[59] This approach is not unlike that employed in California for the acquisition of demand response. In December 2017, the CPUC approved a 5-year budget for 2018-2022 of $1.16 billion for utility-operated DR programs that will provide approximately 1,600 MWs of DR capacity by 2022. The costs of the programs are from ratepayers through retail electricity rates. CPUC Decision D.17-12-003.

program development aligns the overall goal remains aligned with the Company's identified resource needs. PGE has identified areas for improved alignment between IRP planning and the on-the-ground experience gained through program deployment. In the near term, our priorities are:

- Improved Characterization of Flexible Load Program Attributes: The three key resource attributes within IRP planning include: cost; performance constraints; and, for flexible load, customer participation. As PGE gains experience operating programs in our service territory, we can inform these three key attributes with information gained from PGE's deployment of flexible load programs with our customers.
- Improved Quantification of Flexible Load Program Benefits: In recent years, PGE gained expertise at incorporating system value for VERs and energy storage in terms of capacity, energy, and flexibility into IRP modeling. PGE can leverage and adapt this expertise to better incorporate the unique characteristics of flexible load programs.
- Moving Toward Endogenous Treatment Within Portfolio Analysis: In the long term, PGE seeks to incorporate flexible load endogenously in the IRP, rather than exogenously via third party studies. PGE expects this to be challenging because the attributes of flexible load resources are so different from those considered in traditional planning exercises. PGE expects that more holistic treatment of flexible load within the IRP will require incremental improvements over the course of multiple planning cycles, similar to the process for incorporating VERs and energy storage.

As PGE works to develop more innovative approaches to flexible load within the IRP process, there are some aspects of the current practice that will be important to retain. The current practice utilizes the IRP process to establish high level goals for flexible load deployment but does not rely upon the IRP to set prescriptive program-specific targets or to conduct cost effectiveness analysis for specific programs as they are designed and deployed. The most appropriate role for the IRP will continue to be high level goal setting, while program-specific decision-making is built on the insight and expertise of program staff, based on the current opportunities within PGE's service territory.

- Continue using the IRP to set overall system goals for flexible load deployment,
- Continue setting prescriptive targets and details at the program level,
- Continue analyzing cost-effectiveness outside of the IRP.

PGE discusses the role of Distribution System Planning in Section 3.9 and 3.10.

3.4.2 Program and Budget Planning

Taking the goals identified through the IRP process, PGE program staff will develop a multiyear plan to achieve the goals. This plan will cover both the goals identified for the near term as well as the longer-term achievable potential. The plan will cover the types and volume of activities along with the demonstrations and pilots necessary to meet longer term objectives. As part of the multiyear plan, PGE program staff will identify a two-year budget. This process along with reporting requirements and cadence is described in further detail below.

3.4.2.1 Program Planning

To develop the portfolio of programs necessary to achieve PGE's flexible load acquisition goals, PGE program staff will identify the market strategy and program(s) suited for each area of identified potential. These will be defined by the nature of the market opportunity. For example, programs are often grouped around sectors (e.g., residential, commercial, industrial, agriculture), new versus existing construction, technologies with widget-based savings versus those requiring a more customized analysis, or the channel through which potential program participants are reached, such as retail or contractor networks. As described above, bundling these offerings when marketing programs to customers is a best practice and a necessary step on the pathway to cost effectiveness.

Each program will be comprised of one or more flexible load products or services. These will be based on the nature of the product or service and the level of confidence in the amount of flexible load. The opportunities can be classified among the following types:

1. **Demonstration Projects** will be used when products or services have a fair degree of uncertainty for one or more aspects of performance. These measures require specific testing or experimentation. Generally, the uncertainties are technical in nature and testing will be done on a limited basis to explore new approaches to deployment, aggregation, or customer participation. PGE will identify the plans and resources necessary for these measures. Unlike energy efficiency, where the region has collectively invested in demonstration work through the RTF and NEEA, PGE does not have such supporting infrastructure for flexible load. As a result, PGE must be allowed to conduct small scale demonstration projects as seen in the Testbed.

   Presently, as outlined above, the Testbed is PGE's primary conduit for demonstration work. This work is funded through a separate deferral. The proposed multiyear plan and budget will reflect how the Testbed is used and will account for Testbed funding. Any demonstration work that PGE identifies as necessary to conduct outside the Testbed will also be part of the multiyear plan and submitted to the Commission for funding approval. The onus will be on PGE to both demonstrate incremental funding is needed and that the project will benefit our flexible load portfolio long term. As noted in the Commission's LC 66 Testbed white paper, demonstration work will save money and accelerate development of flexible load resources[60]. PGE proposes funding for these activities be small and discrete but not be factored into portfolio cost effectiveness. Demonstration projects are not meant to be cost effective. The following figure shows the demonstration process

[60] LC 66 , Staff Final Comments, Appendix A, May 12, 2017 available at https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=lc66hac132649.pdf&DocketID=20423&numSequence=111.

leading to pilot development. For all Testbed demonstration the DRRC would continue to approve proposal for demonstration work. Where Testbed funds are being used the DRRC would have final approval or denial of the proposed work. The process shown below includes an internal approval by Product Lifecycle Management for continuity of planning and budgeting. The multiyear planning process proposed along with the quarterly DRAG meeting would further inform stakeholders and Commission Staff of demonstration development and progress.

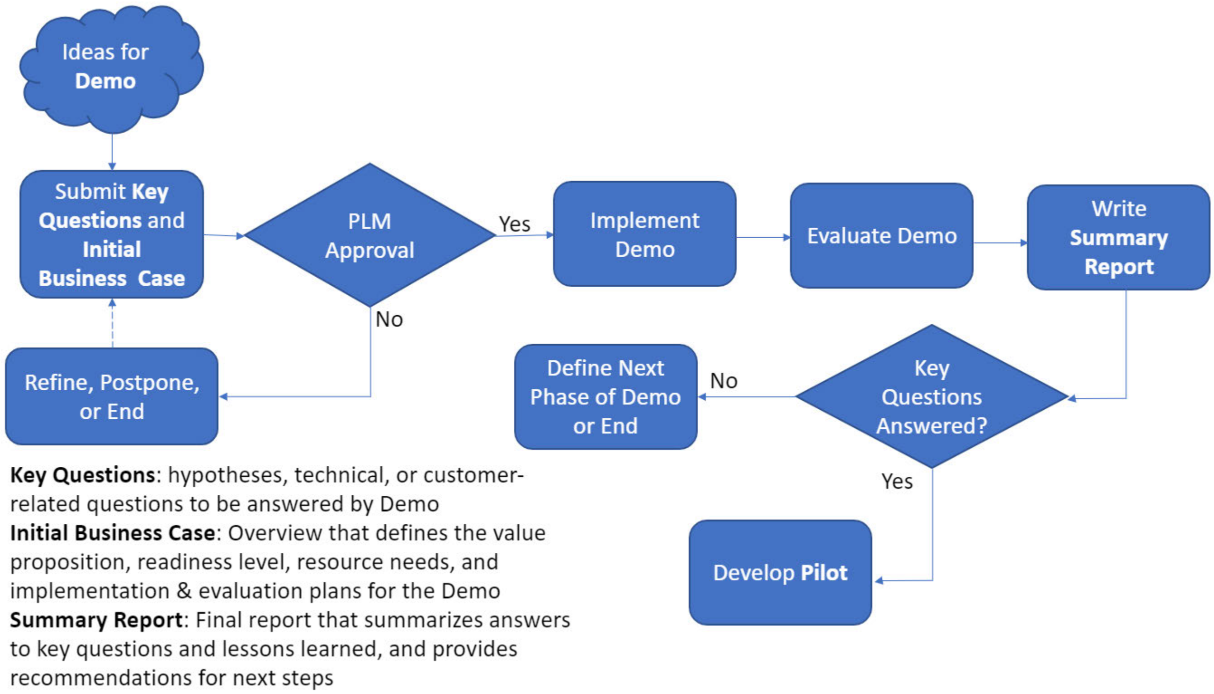


Figure 18 – Demonstration Process

2. **Pilots** are used for products and services showing a promising path to cost-effective deployment. These resources will be incorporated into PGE customer program operations but are at a scale too small to be incorporated into PGE's real time operations. Pilots are typically used to answer a specific number of limited questions about market strategies or program participation. Pilots are accompanied by a plan detailing the questions to be addressed and the evaluation strategy used to answer them. Creating a plan for each pilot helps PGE prioritize and coordinate resources across pilots and will ensure that the plan aligns with the necessary resource objectives Pilots begin with the creation of a Business Case. The creation of a Business Case assures justification for the resource spend. The business case also clearly defines the objectives, resources, and team roles necessary for a successful deployment. The managers of each group whose work will support the pilot will approve or deny the pilot proposal through the Project Lifecycle Management. Major considerations for approval will include availability of resources, demonstration of a clear pathway to cost effectiveness.

Project Lifecycle Management approval requires detailed plans for research and evaluation. These plans include the goals and indicators of pilot success, identification of the research questions, and the resources needed to implement the pilot. At the completion of the pilot, a memo is prepared to document the findings. Based on the results of the pilot, next steps will be determined. A diagram of this process is shown below:

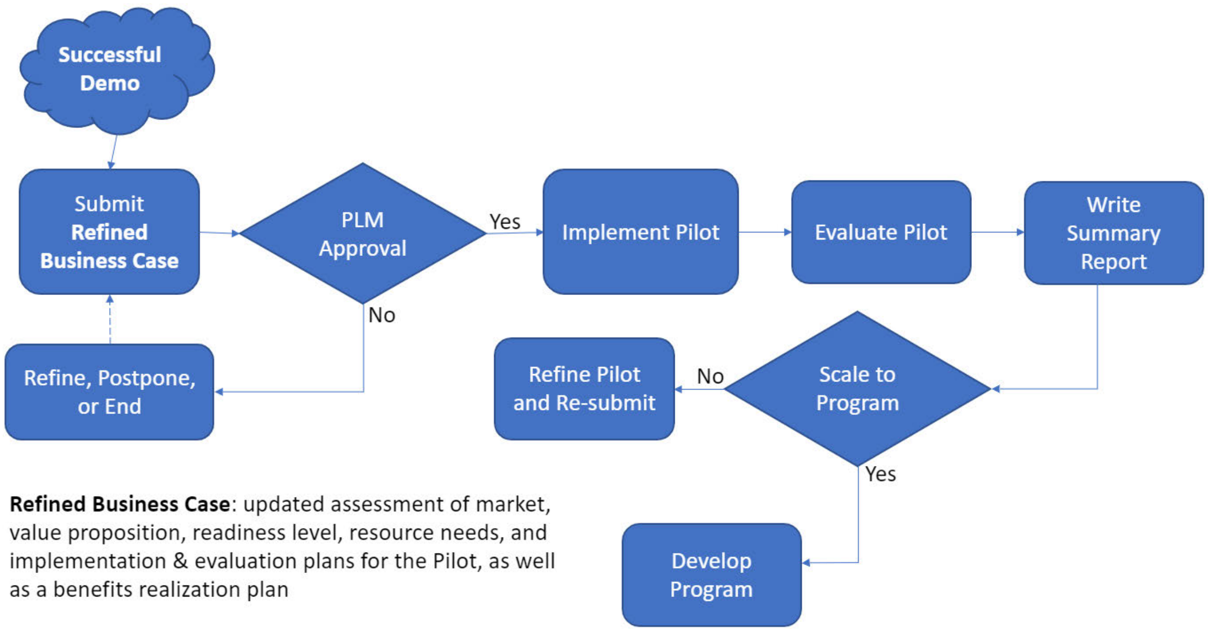


Figure 19 – Pilot Process

3. **Programs** exhibit a high degree of regularity in both impact and implementation costs. On average, these products and services are cost effective across a wide variety of metrics and methodologies defined through the IRP and/or DRO processes. Through a series of documented deliverables required to advance an offering through the PLM phase gates, PGE is able to design, build, and launch demos, pilots, and programs that result in proposal filings at the Commission. The diagram below details the iterative and collaborative process PGE will follow and the roles for PGE staff:

4. In addition to the demonstration to program process for offering development, PGE must carve out space for other high value flexible load offerings, such as large custom projects and offerings capable of providing significant EE and DR value. Custom projects are those in which the impact and cost are unique to each implementation of a measure and an analysis is performed to estimate the quantity of flexible load, implementation cost, and cost effectiveness of a measure beforehand. These are common for programs targeting larger commercial and industrial facilities. For these opportunities, the size of the flexible

load justifies the additional work and complexity involved. Custom projects are typically implemented with calculators built to determine the cost effectiveness and incentive for each instance based on the estimated savings and implementation costs.

Solutions capable of providing overlapping EE and flexible load benefits may also require additional time and resources, as they generally provide high flexible load value. Potential overlap with EE includes heat pump water heaters, which provide both EE and flexible load; smart thermostats; and even bundled measures where a combination of EE and DR measures may provide benefits beyond the sum of their individual components. An example of this last category could include the bundling of weatherization in combination with a smart thermostat, in which additional weatherization would allow for longer and/or larger thermostat setbacks for DR. In these instances of combined EE and DR opportunities, PGE will work with Energy Trust in an approach that considers both the EE and flexible load benefits. PGE will work with Energy Trust to co-develop the tools and processes necessary for such an approach, including the development of offerings, roles for market deployment, and funding/cost allocations.

Finally, as part of the multiyear planning process, PGE will consider the various market delivery pathways to reaching program participants. Included in these possible strategies are the use of a Program Management Contractor (PMC), Program Delivery Contractors (PDC), and direct-to-customer approaches. It is important to note that in both of these models, the contractor remains directly under the oversight of the utility and therefore under the Commission’s jurisdiction. Additionally, PMCs and PDCs typically are paid directly for their services rather than through the splitting of the customer’s incentive. These are key differences between this program model and the third-party DR provider model described above.

PGE will share its program and market strategies with stakeholders during the development of its multiyear plan along with the accompanying budget, discussed below.

3.4.3 Budget Development

PGE proposes to budget on an annual basis in rolling two-year periods, on the same cycle as the Energy Trust. Running parallel budget and program planning cycles can create synergies, increase deployment, and enhance savings. PGE program staff will use the goals set for the two-year period and the strategies identified to determine the budget necessary for each of the two years. The budget will consider fixed costs such as contracting, as well as variable costs such as incentives, which are measured on a per widget or per unit of flexible load.

The process of budgeting will consist of two development rounds. A first round will consist of the initial estimates developed by program staff, to be reviewed with stakeholders as part of the development of the multiyear plan. Program budgets are also reviewed to ensure consistency with a reasonable expectation of funding, recognizing that year-over-year cost increases may need to be limited.

PGE aims to have a transparent and open process, which allows stakeholders to engage in PGE’s program planning and evaluation. To achieve this, PGE will create a multiyear plan and budget highlights program progress, successes, and areas of improvement, and cost effectiveness. This plan will be made publicly available and PGE will solicit feedback from Commission Staff and interested stakeholders. The plan intends to consolidate existing reports, creating efficiencies and streamlining reporting mechanisms. The plan will reflect all of PGE's behind-the-meter activity including DR, energy storage, electric vehicle load control, rate schedule development, microgrid activity (including that connected with distributed resource planning), self-generation, activity coordinated with Energy Trust, and other marketing, outreach, and educational activities.

After this review, budgets will be revised by program managers and become the final operating budget. This budget will determine the funding needed through the recovery mechanism, while accounting for any carryover of unspent funds from the previous year and any funding reserves deemed necessary.

This approach will set a known budget for a two-year period of resource procurement and will allow portfolio activity to be flexible within the time period. This will give PGE the flexibility to balance minor variances from expected activity levels across the portfolio to take advantage of opportunities as they emerge[61]. The stability of funding encourages the utility to work with its resources most efficiently.

By following a process similar to Energy Trust, PGE will be able to identify and align areas for collaboration with the Energy Trust, including developing market strategies, joint measure development, and deployment of resources. This practice will require PGE to plan internal resource allocation and also identify when, where, and at what cost contracting services should be used, requiring PGE to compete its internal costs against third party PMCs and PDCs.

3.4.4 Program Management

This approach will require PGE to manage its flexible load programs on an ongoing basis, including tracking of program-related and overhead spending; program acquisitions of capacity, energy, and ancillary resources; and program incentive budgets and spending. Consistent with Energy Trust's approach to program management, all activity will be tracked in a manner related to the method used in sales forecasting in other industries, where activity is tracked and categorized in terms of its likelihood of follow through, from initial leads to offers, commitments, and completed installations. Insights from the Testbed's load disaggregation work will inform tracking and marketing approaches to improve effectiveness.

For compatibility with Energy Trust's data on completed EE projects, PGE will track its flexible load activity using a data model, consisting of the projects, site(s) where projects are completed, participants involved in the project, and any measures or other activity associated with the project, including energy and/or capacity, measure costs, and incentives provided. A basic diagram of this model is shown below:

[61] For example, if PGE saw growth above forecast in multifamily new construction

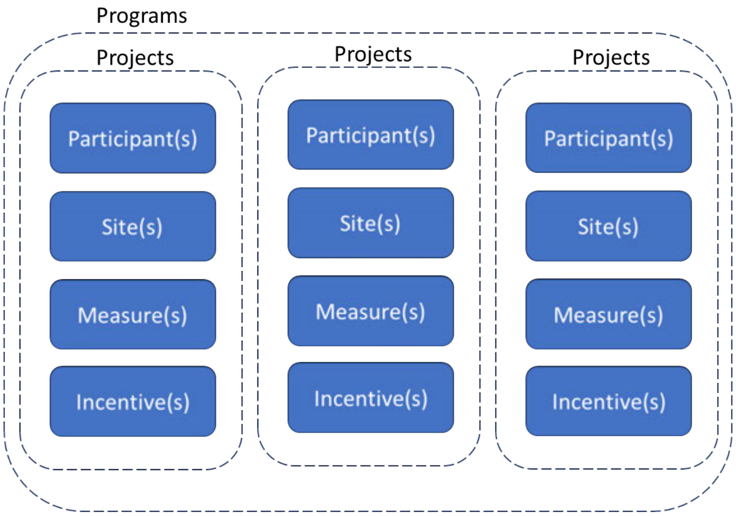


Figure 20 – Repeatable Data Model to be used across Flexible Load Activities

Over the program implementation cycle, there are three measurement points for savings. These are: **Planning savings** that measure expected savings prior to the launch of a pilot or program; **Average realized savings** which are measured during the operation of a pilot or program and **Evaluated Savings** which are measured after the fact by independent third parties. PGE would like to work with the Commission to identify the appropriate methodologies and inputs for each of these measurement points.

3.4.5 Program Evaluation

PGE will conduct regular evaluations of its flexible load activities. Consistent with current and best practices, each program will undergo process and impact evaluations. Energy Trust typically follows a process of evaluating several program years in one evaluation for cost efficiency:

- **Process evaluations** are conducted to review the effectiveness of program processes. During a process evaluation, the evaluators will typically interview program participants to gauge their level of satisfaction with the various components of a program. Evaluators will also interview those program staff involved in the day-to-day and overall management of a program for perspective on the performance of the program as well.

- **Impact evaluations** are conducted to determine the extent to which a program's claimed achievements have been realized. This is referred to as the realization rate and is often applied to savings after the fact.

Both types of evaluations will be conducted by third party evaluators. The evaluators will be selected through a competitive bidding process from a pool of qualified contractors. Evaluation results will be shared and reviewed with the Demand Response Advisory Group (DRAG) to ensure accountability and neutrality in the results, after which evaluations will be posted publicly.

These evaluations will be a critical component to inform future program planning. Process evaluations help to inform program design by highlighting potential areas of concern or evaluating improvements that have been implemented. Impact evaluations can inform future estimates of program achievements by informing things such as the technical realization rate and participation in DR events.

3.4.6 Reporting

To keep the Commission and other stakeholders informed of PGE's activities, PGE will report on its activity through various reporting channels:

- PGE will provide bi-annual updates on expenditures and incentives to Commission Staff through a simple spreadsheet tracker during the first two years. After two years, updates would occur annually. PGE proposes more frequent updates initially in recognition of the novelty of the proposed process change.
- Similarly, PGE would provide quarterly updates during DRAG meetings on program information, including number of sites or customer served and capacity acquisitions. This would shift to yearly reporting after the first two years. The quarterly DRAG meetings offer a venue for more in-depth discussions. These meetings allow for frequent Commission staff and stakeholder input.
- In-depth annual reports will detail the achievements of PGE's flexible load programs from the prior year. This will include overall capacity and flexible load acquisitions in relation to the program goals, along with financial details such as incentives and expenditures relative to budgets. A proposed list of reporting practices, contents, and cadence for the first two years is provided in the table below. Thereafter PGE would switch to yearly reporting:

Table 3 – Report Contents and Cadence First Two years

Metric	Portfolio Level	Cadence	Program Level	Cadence	Notes
Flexible energy and capacity acquired	✓	Y	✓	Y	Totals relative to annual goals
Incentives Provided	✓	Y	✓	B	
Expenditures	✓	Y	✓	B	Relative to budgets
Levelized Costs	✓	Y	✓	Y	
Total Resource Cost Test	✓	Y	✓	Y	Benefit-cost ratio
Utility Cost Test	✓	Y	✓	Y	Benefit-cost ratio
Administrative Costs	✓	Y	✗	Y	As percent of annual expenditures
Customer Satisfaction		Y	✓	Y	From evaluations
Sites/Customers served	✓	Y	✓	B	Some C&I customers have multiple sites
Schedule 135 Recovery	✓	Y	✓	Y	
Goal Setting	✓	Y	✓	Y	
Capacity Acquisition Reporting	✓	Y	✓	B	

Y = Yearly B = Bi-annually

As noted above, PGE will report on the cost-effectiveness of its overall flexible load portfolio, as well as the cost-effectiveness of individual programs and products. Overall portfolio cost effectiveness will allow PGE to meet the identified goals while still effectively allocating resources to a mix of emerging and well-established activity. This gives the utility the flexibility to fund demonstrations and pilots for emerging measures that may not be cost-effective in the near term, while supporting resource acquisition through programs at scale and maintaining cost-effectiveness at the portfolio level. To meet PGE's ambitious flexible load goals, it must acquire cost-effective flexible load in the near term while also supporting the development of additional resources.

This regular reporting will give the Commission and stakeholders visibility into PGE's work and the costs relative to its accomplishments. It will also obligate PGE to transparently identify any issues move swiftly towards their resolution.

3.5 Product Management Lifecycle

Organization	**Create leadership support and accountability, dedicated resources and cross functional collaboration within the utility for effective program development**

Since 2014, PGE has utilized a Product Lifecycle Management (PLM) process to systematically prioritize the development of the portfolio of products. PLM provides oversight of products from concept through to development, operationalization, and reassessment. Figure 21 illustrates how PLM answers key questions regarding the product portfolio, including is the idea or product viable/feasible? is there a market and business case? is the product ready to launch? Post-launch, PLM reviews product performance, as well as whether it needs to be updated, discontinued, and / or replaced. The following section summarizes PGE's current PLM processes. It is important to note that these processes are continually refined based on lessons learned during execution of the process.

Figure 21 – Product Lifecycle

PLM oversight of the product portfolio is delivered via a system of controls. First among these is a governance framework to ensure clear management of the process. The process owner coordinates product development and ensures that relevant stakeholders have been engaged and that an informed recommendation is brought forward for consideration. The approver has ultimate authority and accountability for product lifecycle decisions. The process owner engages subject matter experts on relevant matters; they inform recommendations that the process owner brings forward for consideration.

A regular cadence of formalized meetings provides several controls. Weekly management meetings assess new development opportunities, identify and remediate issues, and schedule product development. Biweekly Advisory Committee meetings communicate the status of efforts in a consistent and timely manner, provide a forum for formal decisions regarding the product lifecycle, and deliver a quarterly review at the portfolio level.

An ongoing market assessment identifies customer needs and PLM intake controls ensure that product ideas address those needs. Prioritization criteria ensure that product ideas are in line with PGE's strategic imperatives to decarbonize, electrify, and perform. Market "fit" is determined by market research to ensure that development efforts are in line with customer needs.

PGE's development and reporting controls include a suite of standardized planning documents. Chief among these is the Product Plan, whose stage gate criteria ensure the requisite steps have been completed at the pertinent stage of the product lifecycle. The Product Plan is an umbrella document that encompasses a swath of subsidiary controls. It starts with the Product Proposal and Development Schedule, and proceeds through the Business Case, Financial Analyses and Budget Tracking. The Product Plan lays out Stakeholder Roles and Responsibilities and includes a Logic Model to ensure that products deliver on and are assessed against strategic goals. It compiles distinct product planning documents including development, marketing, communications, evaluation, data management, and risk management plans. The Product Plan also includes an ongoing performance review to provide oversight into the operation of developed products. Related PLM documents include the product brief, which provides a quick overview of products for stakeholders. Lastly, the stage gate recommendations and decision log documents respectively memorialize the process owner's recommendations and the approver's decisions after each stage gate, including any contingencies thereto.

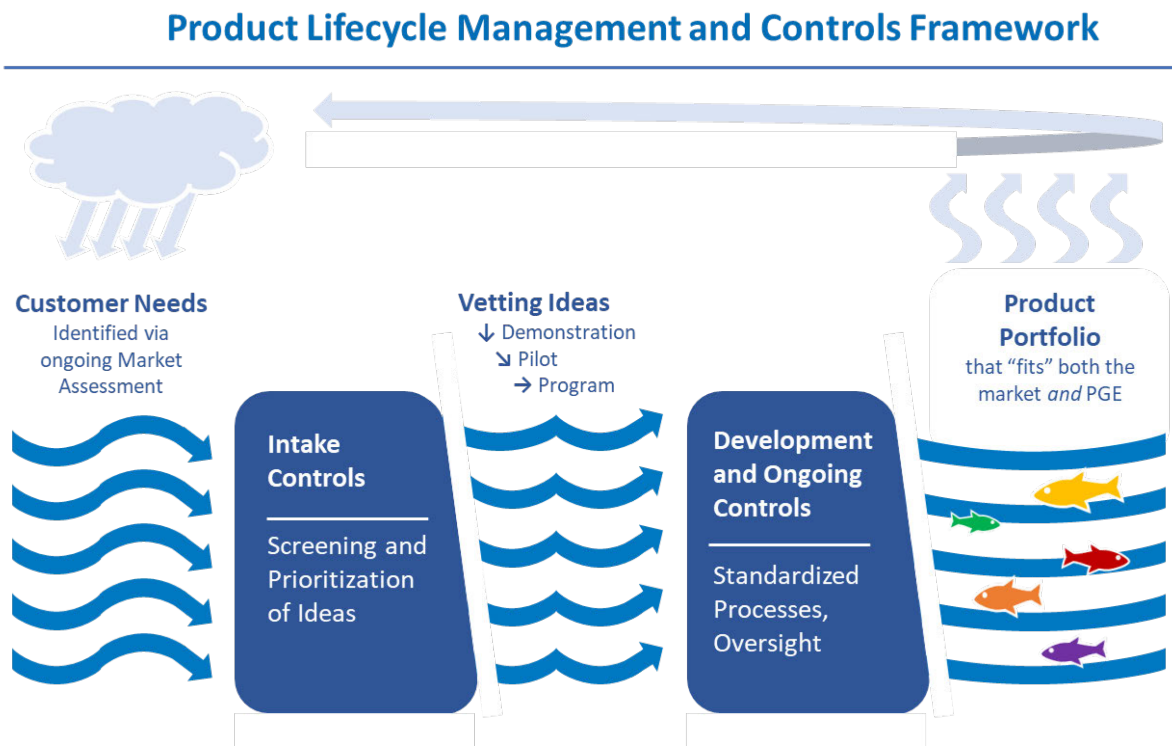


Figure 22 – Product Lifecycle Management and Control Framework

Figure 22 and the above descriptions illustrate how the PLM control framework provides robust oversight of PGE's product portfolio. It delivers better visibility into the product lifecycle; identifies controls that are right-sized to the size and complexity of the effort; establishes clear expectations, ensures timely communication, strengthens alignment with internal stakeholders, and forces standardization so that stakeholders know what to expect and when.

3.6 Stakeholder Engagement

Stakeholder Engagement	Collaborate effectively across industry stakeholders to design and execute meaningful projects

Stakeholder engagement and support is essential for meeting the aggressive, innovative goals that PGE and the OPUC have adopted for flexible load deployment. PGE knows that technology providers, regulators, customers, and advocates must collaborate on new concepts, establish common ground, and avoid unproductive disputes in the pursuit of cutting-edge projects. This is why PGE has established the DRRC for the Testbed. The Committee is seated by participating cities, the Citizens' Utility Board, NWPCC staff, NEEA, the Energy Trust, the Pacific Northwest National Laboratory (PNNL), the Oregon Department of Energy (ODOE), the Alliance of Western Energy Consumers (AWEC), Commission Staff, and other partner organizations. PGE collaborates with these stakeholders to design and implement our Testbed and flexible load demonstration projects.

Additionally, PGE is coordinating with Commission through DRAG meetings, where PGE meets with Staff and, when invited, the Energy Trust, to report and seek guidance on project development.

Furthermore, in order to improve communications and engagement with our customers, PGE hired three Community Relationship Managers within the Smart Grid Testbed. Our Community Relationship Managers have begun implementing a Testbed community engagement strategic plan to inform practices throughout our flexible load activity. The community engagement strategic plan identifies the goals and objectives of outreach efforts of the Community Relationship Managers working in the Smart Grid Testbed and is outlined below:

Table 4 – Smart Grid Testbed's Community Engagement Strategic Plan

Goal	Objectives	Outcomes	Deliverable/Metric
Identify and build durable relationships with key stakeholders	• Identify and create inventory of stakeholders and establish points of contact for key/priority relationships	• Engagement with key stakeholders and mechanisms for ongoing communication	• List of prioritized stakeholders with assigned relationship owners
Identify disparities in service or program participation	• Collect and synthesize customer data from all relevant sources • Analyze data and identify areas where disparities in services and/or programs exist	• Shared themes and insights from test bed data sources • Share identified barriers to participation specific to environmental/social/climate justice communities • Share recommendations for programmatic changes based on the data	• Community Snapshot • Quarterly Community Insights Meeting • End of project evaluation report
Leverage community engagement best practice	• Identify and leverage best practices in community engagement • Research community engagement practices at other utilities • Apply equity lens to all community engagement planning and activities	• Stakeholders and community members included in planning and implementing community engagement strategies • Approach adopted for clear and transparent communication about the participant's role and level of influence	• Collective community engagement work plan • Individual testbed-specific work plans
Establish Outreach PACE model and facilitate implementation of community and key stakeholders' feedback	• Provide insights gained from SGTB community engagement to appropriate PGE departments	• CRM-led cross-functional Quarterly Community Insights meeting and Community Outreach PACE	• Community Outreach PACE • List of prioritized stakeholders with assigned relationship owners
Demonstrate a commitment to continuous improvement	• Review community engagement strategic plan regularly • Review best practices and current engagement strategies and techniques	• Documented lessons learned and application of methodology to aid in evaluating continuous improvement and applicability to broader service territory longer term • Incorporate best practices and new engagement strategies and techniques	• Repository of lessons learned, best practices, strategies and techniques for community engagement

The primary goal of the SGTB is to identify new strategies that will help address the 2021 electric generation resource needs identified in PGE's 2016 Integrated Resource Plan (IRP), and confirmed in the 2019 IRP. These strategies are centered around driving demand Response (DR) and flexible Loads, which are identified as a carbon free, cost-effective, customer-based resource which helps address anticipated 2021 resource needs. Foundational to the success of the project is ensuring that we are focused on understanding the ability of customers and communities within the SGTB to participate in PGE DR programs, and within that context, identifying their desire, motivations and tensions (barriers to entry). The creation of the Community Relations Manager (CRM) positions provides a channel for engaging underrepresented and underserved customers, increasing knowledge about the SGTB and load flexibility, and building/nurturing relationships with stakeholders to reinforce PGE's commitment to this work' community engagement efforts will be focused within the three testbed communities: North Portland, Hillsboro, and Milwaukie. Testbed efforts will also provide a means for PGE to demonstrate the value of, and need for, broader community engagement across our service territory to achieve DR uptake and other clean and equitable energy future outcomes.

3.6.1 Empowering community voices

The energy industry is evolving rapidly, and those who are affected by disparities must have a say in the change. PGE is a trusted advisor and critical touchpoint for helping all people understand how the energy system works, how to advocate in regulatory spaces and which programs might benefit them.

3.6.2 Eliminating barriers in public process

Community groups play a critical role in shaping public processes and must continue to be invited to discussions about equitable policymaking. For example, in 2017, the Oregon State Legislature passed Senate Bill (SB) 978, which required a public process to explore how new technologies and policies might impact the electricity regulatory system. SB 978 eased the path for groups like the Coalition of Communities of Color, OPAL Environmental Justice and Verde to bring their voices to the Oregon Public Utility Commission, where they advocated for the protection for low-income ratepayers, the development of community-based renewable energy projects, workforce diversity in the energy sector and other key issues

One barrier to inclusive participation in energy public processes is a lack of funding to support historically excluded stakeholders. Where appropriate, community advocates should be compensated for their unique consultation. PGE, Pacific Power and other partners submitted an agreement to make funds available to community organizations to cover expenses associated with their participation in SB 978.

3.6.3 Better data sharing

We believe inclusive engagement is possible only when information about who benefits from programs and services is shared openly. In collaboration with state and federal agencies, OPUC, Community Action Program (CAP) agencies, and community-based organizations, PGE will work to provide better demographic data on our pilots and programs by identifying the benefits and burdens associated with our energy system. This will help stakeholders understand where to focus further efforts.

3.6.4 Enhancing customer interactions

As we engage with customers throughout our service area, it's critical to keep in mind that communication needs vary. For example, not everyone will speak English or have access to online resources.

PGE has the responsibility to serve customers whose needs, whether related to income, language, health, age, or other situations, differ from the majority of our customers. We regularly review our practices to ensure we are accommodating these customers. For example, we have staffed our contact center with Spanish-speaking representatives. Thanks to our diverse workforce, we can also call upon employees who speak Russian, Farsi and other languages when additional help is needed. As our service area becomes more multicultural and digital, we're leaning into spaces that are new and challenging. We must continue to set the bar higher for creating smooth, accessible customer experiences. Without Smart Grid Testbed we have issued collateral in Spanish, English and Russian.

3.7 Cross-Industry Collaboration

Cross-Industry Collaboration	Share best practices and lessons among utilities to accelerate effective demonstration to pilot to program evolution

PGE has been working to establish coordination with the Energy Trust through the Testbed via the DRRC, DRAG and regular monthly coordination meetings within the Testbed. PGE has been working with the Energy Trust to coordinate our approach to residential and commercial thermostats, single family heat pump water heater, ductless heat pumps, roof top solar plus storage and strategic energy management. PGE view Energy Trust of Oregon as is most important partner in flexible load development. Our proposal to move to multiyear planning and budgeting should accelerate and better our coordination and collaboration.

Additionally, PGE has recently opened a conversation with PacifiCorp about co-development of demonstration and pilot projects. PGE is hopeful that PacifiCorp and PGE can identify beneficial opportunities which may save both utilities' customers money. Lastly, PGE has been sharing our work with the region through various regional forums such as the NWPCC DRAC, and also nationally through EPRI and the Peak Load Management Alliance.

Industry Collaboration is important to the development of Flexible Load. Analogous efforts to support energy efficiency development have been established in the Northwest. These activities and collective investment in entities like NEEA and the RTF provide significant benefits to the region's utilities, are the envy of other regions, and make our approach to energy efficiency one of the, if not the most well established in the country. PGE views such cross-industry collaboration as a necessity for flexible load development and will pursue similar establishment.

3.8 Utility Role in Flexible Load Development

3.8.1 PGE is Optimally Positioned to Develop and Optimize Flexible Load Resources

Flexible loads need to be dispatched automatically and at grid scale, to ensure maximum benefits are achieved. This can only be accomplished when integrated with and managed by the grid operator. PGE has the planning, development, and operations experience needed to optimize flexible load across a portfolio of value streams.

Planning for least cost resource development and acquisition is key to meeting our customer's needs. PGE's IRP provides strategic direction for resource acquisition. Flexible Load is inextricably linked both to the IRP process and to PGE's commitment to customers to decarbonize at least cost.

Additionally, in order for flexible load to reliably provide grid services, it must integrate with the monitoring and dispatch tools used by PGE's real time operations[62]. PGE is required to maintain the balance between generation and load on a second to second basis, and to meet NERC and WECC reliability standards where performance is measured in seconds and minutes. For flexible load to be fully optimized in real time operations, it must be fully visible and dispatchable by PGE's operations staff.

3.8.2 Optimizing Flexible Load as an Integrated Resource

PGE views Flexible Load as a system resource, a tool with which to help decarbonize our system and integrate variable renewable resources at least cost while maintaining reliability. We commissioned our Decarb Study[63] to understand if a decarbonized energy future is attainable while serving the growing electric and energy needs of our customers. The findings of the study show a decarbonized future is attainable even with today's technology, but to enable the kind of future suggested by the study, major changes are required in the way our society produces, delivers, and uses all forms of energy. This includes driving down greenhouse gas emissions in our own resource portfolio while creating a modernized, smart grid to help efficiently integrate clean, renewable resources and enable electrification. Flexible loads are key components of this

[62] For example, PGE's balancing authority uses OSI's monarch platform to provide Supervisory Control and Data Acquisition (SCADA), Energy Management System (EMS), and Enterprise PI for real-time monitoring and tagging. PGE also uses a suite of operations tools from OATI, including the OASIS platform, webEIM, webTrans.

[63] Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory, April 24, 2018, available at https://investors.portlandgeneral.com/static-files/6e630aff-fcff-44e2-9ddb-82232f24bcd4.

modernized grid and the study found – in the High Electrification Pathway – that more than 900MW of flexible load could be needed by 2050. To achieve this success, PGE must build, monitor and utilize flexible load in real-time. Enabling the full capabilities of flexible load requires PGE to make investments today not only to build the flexible load resource but also to capture the greatest benefit through reliable, secure real-time control that is fully integrated with PGE's operations.

In order for flexible load to support decarbonization in the way envisioned by PGE's Decarb Study, flexible load must be aggregated into Virtual Power Plants as described in Chapter 1. These Virtual Power Plants must then be optimized in real time across the range of services that they are capable of providing. For example, if the Virtual Power Plant is providing distribution deferral, the limitations of the distribution equipment must be respected in order for the flexible load to also provide flexibility reserves or other grid services. In order to optimize flexible load across multiple value streams, PGE must be able to integrate it into PGE real time dispatch and monitoring systems. This integration is what enables flexible load to operate on par with generation resources.

PGE is committed to the investments necessary to support the utilization and optimization of flexible load. These investments include: an ADMS, distribution automation; and Distributed Energy Resource Management Systems (DERMS). These are the tools and the integrated operating platforms that will enable PGE's customers to realize the greatest overall value from flexible load. PGE's Smart Grid Report outlines this vision[64].

The Testbed offers PGE an opportunity to test strategies to implement this new integrated grid platform[65]. Within our Testbed, PGE is investing in several demonstration efforts. Section 3.11 of this Plan outlines a series of related flexible load demonstration projects meant to judiciously approach the implementation of our integrated grid vision. An example is PGE's investment in a demonstration of a standalone DERMS solution which offers a multifaceted opportunity to advance PGE's ability to build the Virtual Power Plant by enabling location-specific monitoring and control. This will be the region's first test of a Virtual Power Plant. PGE is using the Testbed to demonstrate the capability for flexible load to provide a host of grid services.

The integrated grid is a highly complex system that requires controls and monitoring at distinct points as well as modeling and planning to optimize value and grid services. Figure 23 shows how PGE will structure and utilize our investments to capture the greatest value from our flexible load investments, with the goal of enabling their full integration into grid operations.

[64] Oregon Public Utility Commission, UM 1657, July 2019. PGE's 2019 Smart Grid Report.
[65] PGE filed information about the integrated grid platform in our 2019 Smart Grid Report in OPUC Docket UM 1657. Discussion of Integrated Grid can be found through the report but particularly within Section 5.

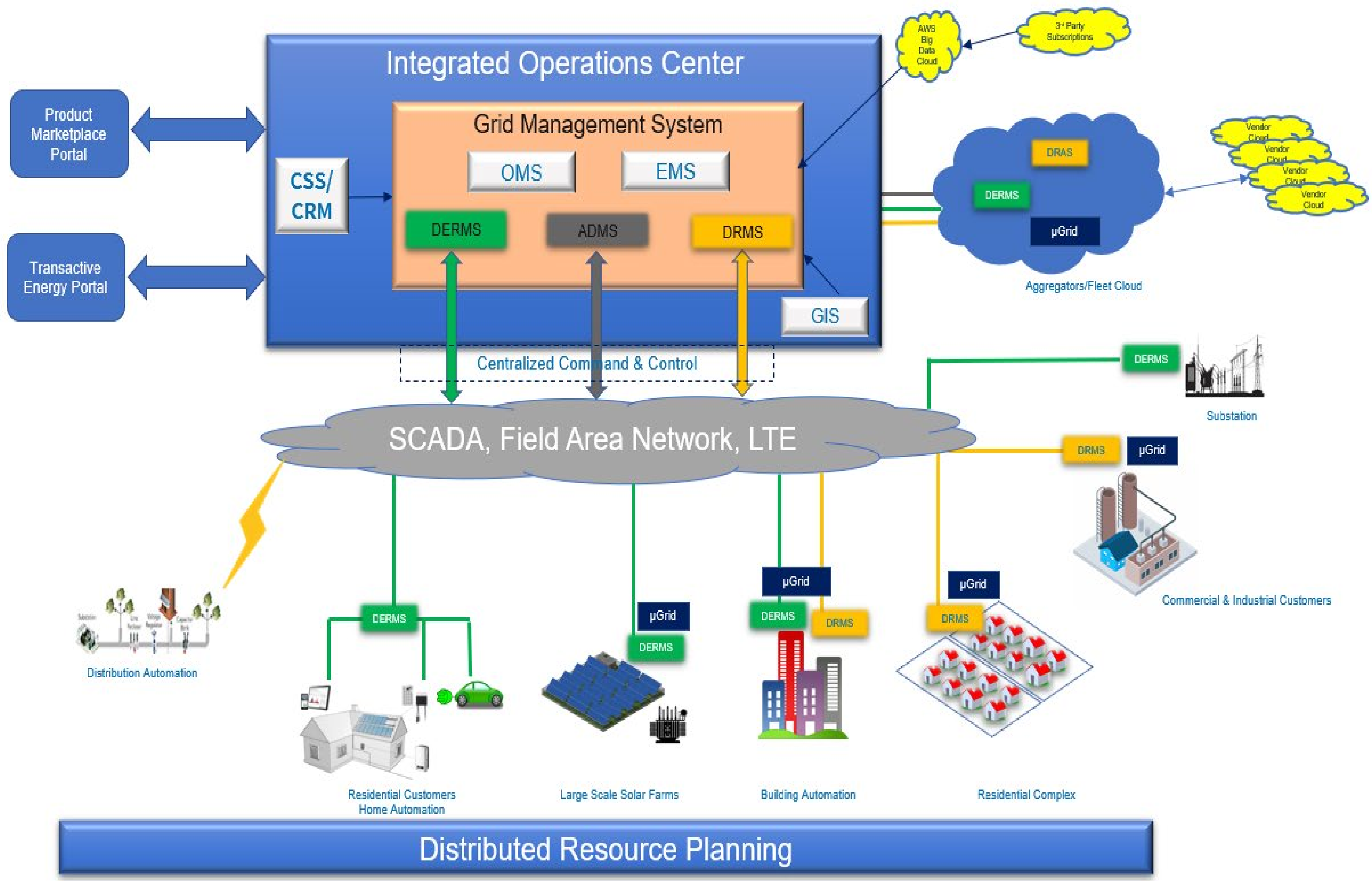


Figure 23 – PGE ADMS Vision

In this integrated approach, all aspects of the flexible load resource are visible, whether through residential grid enabled appliances, an electric vehicle, or through grid interactive buildings and microgrids. Our approach is part of a broader planning effort through our Distribution Resource and Distribution System Planning activity. Clarity of the market potential and reliance on technology to integrate and operate in real-time are necessary to plan, build and operate the resource. This Flexible Load Plan documents PGE's vision and commitment to building a flexible load resource that is fully optimized in PGE's operations. This integration is necessary to capture the full value of flexible load in pursuit of decarbonization at least cost.

3.8.3 PGE as Provider and Operator of Flexible Load

Customer engagement and participation will be critical to achieving long-term decarbonization at the lowest cost to customers, and flexible operation of electrified end uses is a key strategy. The development and optimization of flexible load is a partnership between PGE, the Commission, and our customers. Inserting another entity between PGE as the grid operator and our customer as the provider of flexible load, threatens the optimization, value, and the rate of the resource build. Having overall responsibility for incorporating flexible load into the portfolio allows PGE to strategically partner with third parties in ways that leverage their capabilities without introducing inefficiencies. PGE's envisions partnerships with third parties playing a key role in an efficient, effective flexible load ecosystem. Maintaining an integrated system allows PGE to harness the real-time operational capabilities of these resources.

PGE has learned from past experience, and validated with research into other states, that using third party demand response providers creates poor customer experiences and limited grid value and use. California experimented for several decades with third party demand response providers yet has still not fully integrated flexible load resources into grid operations and the wholesale market[66]. Latency of communication, intra-day coordination and customer protection issues hamper the third party demand response provider approach. Latency of performance arises

[66] In 2003 a working group including CPUC and CEC participants developed a vision for demand response: "All California electric consumers should have the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals, by not later than 2007."
The document also laid out objectives, goals, principles and a timeframe for achieving that vision. In CPUC Decision D.03-06-032, the Commission endorsed several aspects of the vision statement, including a goal of achieving demand response capacity of 5% of annual system peak demand by July 1, 2007. The adopted goals were specified to be above and beyond any "demand response achieved through the emergency programs. See also California Public Utility Commission Decision D.06-1-049 ((November 30, 2006) where the Commission began modifying their approach to demand response and directing utilities to release RFPs for aggregator acquired demand response. See also CPUC Decision D.13-12-029 Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols where the Commission began attempts to integrate demand response into wholesale markets. Finally see CPUC Decision 17-10-017, section 2.3 which shows the Commission still addressing items like mismatched supply plans, wholesale market participation, incorporating and valuing demand response megawatts.

because the utility must contact the third party demand response provider to trigger and manage an event. This limits the types of grid services available and thus the overall grid operations and planning value of flexible load. This added inefficiency would challenge the viability of multi-nodal programs such as hot water heaters and would all but eliminate the potential to optimize for a different service each hour[67].

Third party demand response providers are also not regulated by the OPUC. Additionally, third party demand response providers do not have the same obligations as a utility to serve customers and to ensure reliability. In PJM, NYISO, and ISO-NE, third party demand response providers have manipulated the market through the artificial inflation of customer baselines and other mechanisms. The FERC has taken action against the following third party providers:

- In 2013, Enerwise Global Technologies, Inc directed one of its participating customers to increase its load prior to an event to inflate potential payments. Not only did this implicate the customer in a wrongful act but it was an attempt to extract above market payments without providing a beneficial service to the grid[68].
- In 2013, Competitive Energy Services, LLC engaged in a scheme to fraudulently inflate a customer's energy load baselines and then offer load reductions against that inflated baseline[69].
- In 2012, EnerNOC submitted overstated baseline data for five DR assets, violating ISO-NE's tariff by submitting inaccurate data for settlement without first exercising due diligence[70].
- From 2007-2008, North America Power Partners 1) registered 101 customers before obtaining their authorization or verification of their willingness and ability to participate in the PJM capacity auction; 2) knowingly submitted inaccurate values, overstating the capacity value of their portfolio by 39.5 MW and 3) failed to respond over 9 times to a PJM frequency response event when their resource had been bid in and cleared the auction; no customer was notified of the event or their participation obligation[71].

PGE is concerned that without this direct regulatory oversight, third party providers could have increased opportunities to manipulate participating customer data for financial gain. These demand response providers engaged in these activities despite the oversight of the Market Operator, the independent market monitor, and FERC enforcement action. Additionally, participation in an organized market ensures that all parties are subject to the market operator's

[67] For example, water heaters could provide winter peaking capacity for the morning ramp, then regulation /energy imbalance over mid-day, and again provide peaking capacity over the evening peak.
[68] *Enerwise Global Technologies, Inc*. 143 FERC ¶ 61,218. Issued June 7, 2013
[69] *FERC v. Lincoln Paper & Tissue, Inc*., No. 1:13-cv-13056 (D. Mass.) & *FERC v. Silkman,* No. 1:13-cv-13054 (D. Mass.)
[70] *EnerNOC Inc. and Celerity Energy Partners San Diego LLC*, 141 FERC ¶ 61,211 (2012) (order approving stipulation and consent agreement).
[71] *North America Power Partners*, 133 FERC ¶ 61,089 (2010) (order approving stipulation and consent agreement).

tariff and are thus under the FERC's direct jurisdiction. These providers could extract payments from all customers without providing the contracted grid service, with limited to no regulatory oversight.

In contrast to third party suppliers, a utility is fully under the oversight of the Commission. This is particularly important for PGE because of the predominance of residential customers in our customer mix; therefore, a majority of the available flexible load resides with residential customers. This means two things. First, the relationship between the provider of flexible load programs and services needs to be under direct regulatory oversight to protect against misbehavior and to prevent a third party demand response provider from taking undue advantage of customers who may not understand the value of their participation[72].

In 2017, when PGE ended a contact with a third party demand response provider for non-performance, the entity exited the market, leaving PGE and regulators with questions and concerns[73]. To make the third-party demand response provider model work, the third-party demand response provider negotiates with customers, taking a percentage of performance payments. Customers should have transparency to the value of the service they provide and should be paid commensurately. PGE provides that transparency through filed rates and tariffs. These tariffs transparently lay out how and how much the customer is compensated. The Commission oversees these activities and can request modification at any time.

In an effort to address performance of third party demand response providers, the CPUC's Energy Division began experimenting with an auction mechanism to procure demand response in 2014[74]. Again the results show California is continuing to struggle with third party provided demand response[75].

Recent evaluation of this third-party procurement approach found significant challenges and misgivings. Despite spending a collective $63M over 5 years, the evaluation found third party programs were 1) far less active in the day-ahead market then other demand response resources supplied by the utilities, 2) the prices for these third party megawatts were far less competitive then other resources, 3) these third party demand response megawatts were not effective in offsetting the dispatch of gas plant during peak hours; 4) underperformance was particularly acute among residential demand response providers; 5) pricing for the capacity megawatts provided was not competitive until sometime in 2017; 6) the Commission Staff concluded that prices

[72] CPUC D.08-06-015, Decision Modifying Decision 07-05-029. Where the Commission out of concern over performance gaming and customer compensation made several changes to demand response programs operated by aggregators in the state.
[73] OPUC Order No. 17-429, October 24, 2017, see also first modifications to the EnerNoc contracted requested and approved in OPUC Order No. 16-037, January 2016.
[74] In D.14-12-024, the California Public Utilities Commission (Commission, or CPUC) authorized investor-owned utilities (IOUs) to conduct pilot Demand Response Auction Mechanism (DRAM) auctions in 2015 and 2016 for procuring demand response (DR) capacity aggregated by third-party providers, also referred to as demand response providers (DRPs),1 to be delivered in 2016 and 2017.
[75] California Public Utilities Commission, ED's DRAM Evaluation Updates & Recommendations: Public Workshop, January 16, 2019.

provided were not competitive in the energy markets; and finally 7) Commission Staff could not determine whether the third party approach successfully provided the contracted capacity[76].

It should also be noted that this approach could not produce day-of dispatch. These third-party demand response providers could only supply the contracted megawatts on a day-ahead basis. As PGE pursues decarbonization goals, it will be important to maximize the performance capability of various flexible load programs on all operations horizons—from resource adequacy planning to intra-hour “shimmy” programs. As described in Chapter 1, the true value of flexible load lies in a portfolio of programs operating as a Virtual Power Plant. If, like California’s experiment with third-party DR auctions, the megawatts provided are only available day-ahead, this would significantly lessen the portfolio value of the flexible load.

PGE is expanding our flexible load portfolio to help provide grid services to meet PGE’s planning and reliability obligations. PGE does not support the use of customer dollars to invest in third party demand response provider business models that are unregulated by the PUC. Flexible load offers carbon-free capacity—a resource that is built on a long-term planning basis to provide certainty that PGE will be able to meet peak load events. Third party demand response providers do not have a mandatory obligation to serve load. Giving these parties, whose responsibility to the system is held fast only by a passing monetary interest, the responsibility to build a resource needed to meet reliability and planning obligations would jeopardize grid operations, customer experience, customer prices, reliability and safety.

3.8.4 PGE Can Maximize Value Through Regional Collaboration

Regional collaboration was one of the keys to unlocking the potential for energy efficiency; PGE is working to develop a similar regional approach to demand response and flexible load. To advance and accelerate the development of flexible load PGE understands that investment must be made to shape building codes; appliance standards and communication protocols; interconnection requirements; and integration standards.

The Northwest has made such investments in energy efficiency, and these collective investments have supported the advancement and establishment of energy efficiency. The regional coordination between the region’s utilities, the NWPCC, Bonneville Power Administration (BPA), the Energy Trust and NEEA have had national effect. Investment in this work would likely not have materialized had the region relied on external entities or created a patchwork system of utility directed programmatic investment and external entity program offerings. Similar to our collective regional investment in EE, PGE envisions regional investment and coordination to advance the development of flexible load. PGE staff, staff from the Northwest Energy Coalition (NWEC) and NEEA have initiated discussions about regional coordination for DR and flexible

[76] California Public Utility Commission, Energy Division’s Evaluation of Demand Response Auction Mechanism, Final Report, January 4, 2019.

load. To this end NWEC will be sponsoring a webinar in June on CTA-2045 regional coordination. The Washington Legislature passed House Bill 1444 in 2019 codifying CTA-2045[77].

PGE is working and coordinating with Energy Trust regarding coordinated deployment of flexible load technologies to customers. Energy Trust and PGE are currently coordinating deployment of smart thermostats and solar plus storage; in 2020, we will begin a demonstration project studying the combined EE and DR value of ductless heat pumps.

While coordinated deployment of energy efficiency and DR is a best practice, it is important to note that energy efficiency and flexible loads are not similar in terms of ongoing operations. Energy efficiency programs generally involve engagement with the customer once, while flexible load requires continued engagement and participation because the resource is used as part of grid operations. The energy efficiency investment permanently lessens customer energy demand; flexible load is more complicated as demand is moved throughout the event, hour, day or season to match the needs of the grid

Our coordination work with Energy Trust has only just begun but shows extraordinary promise. This type of partnership will save customers money, better establish the working relationship between the Energy Trust and PGE, create stronger customer experiences, and save customers money. Lastly, this coordination will allow for better resource build than if third party demand response provider were allowed to disrupt what is a promising Oregon-centric approach.

3.8.5 Flexible Load Resource Build Costs Should be Non-by-passable

As mentioned above, flexible load is a long-term real resource in which PGE is investing for the long-term benefit of our system and customers and is recognized, along with energy efficiency, as a preferred resource in Oregon SB 1547 and a strategy identified in the Governor's Executive Order No. 17-20. However, this cost is currently recovered only from cost of service customers, yet the investment provides benefits to all system users. PGE proposes to recover the cost of our flexible load offerings from all system users, and is raising this in Docket No. UM 2024, which is ongoing.

Additionally, while Direct Access customers are currently unable to participate in PGE's flexible load programs, cost-effective flexible load could be available from these customers. Many of these Direct Access customers have expressed interest in participating in Energy Partner. These customers may also wish to participate in the TE and business charging pilots that are currently under development. PGE would like to explore options for Direct Access customers to participate in Flexible Load programs.

3.9 Distributed Resource Planning

Robust distributed energy resource planning is required to achieve our goals around equitable, affordable, and sustainable decarbonization of the energy economy. For this reason, PGE has

[77] Washington 2019 Legislative Session, House Bill 1444. Available at: http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Bills/1444-S.pdf.

established a Distributed Resource Planning (DRP) team focused on the development and application of new planning, operational practices, and tools to help us contend with a changing system. PGE will gain significant experience in planning for flexible loads and DERs within a comprehensive system planning context. In particular, the DRP function which will make progress towards addressing questions related to DER forecasting and potential, grid services, and resource characterization, which will be of mutual value to both DRP and IRP planning activities.

The future DRP will build new capabilities in PGE's core business of planning the electric system. These new capabilities will be fundamental in enabling the Company to leverage the grid as a platform for integrating localized energy resources, while putting PGE in a position to lead the conversation on integrating new technologies in a responsible, measured, and optimal way. This initiative has been designed to proceed flexibly, with minimal investment required to meet immediate needs, and the optionality to accelerate activities if required. PGE is using a phased approach to future DRP work as shown in Figure 24.

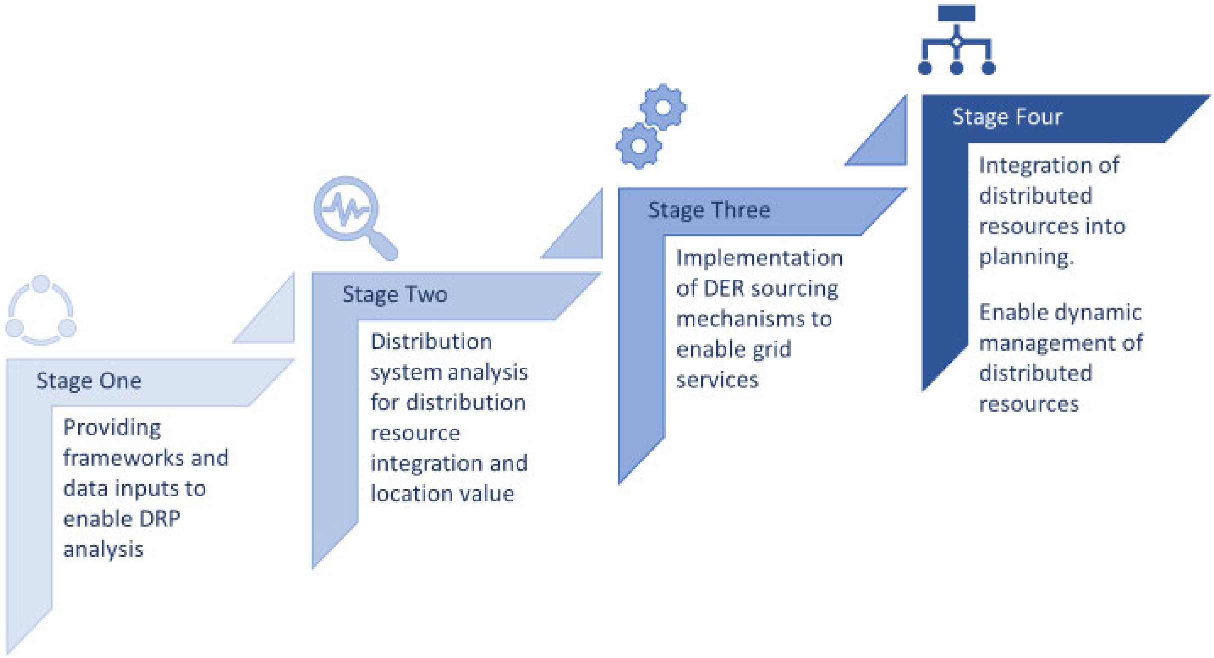


Figure 24 – Four Stages on DRP Implementation

3.9.1 Coordination Between IRP and DSP

PGE continues to advance our understanding of how planning practices can best support the evolution of flexible load. As we evolve our understanding, Distributed Resource Planning will become an important part of PGE's resource planning activity and reporting to the Commission and stakeholders. The four focus areas and the roadmap outlined above are the guiding vision for the detailed work to be conducted.

Currently, PGE conducts comprehensive distribution system planning (DSP) to support a robust and reliable distribution network, but it is not fully integrated with the new market realities engendered by flexible loads and DERs. Through the development of the first formal DSP filing[78], foundational steps to the DSP have already been made in the normal course of business. While UM 2005 is still underway, PGE has already begun working on many of the elements of distribution system planning in a variety of venues. Staff notes in their 2019 white paper[79] that there are a multitude of dockets that touch on elements of DSP across many areas of the business, including Resource Value of Solar[80], the IRP[81], Transportation[82], and Storage dockets[83], as well as the various DR pilots underway[84]. Under the future DSP process, PGE intends to develop tools and capabilities to model DERs including flexible loads. This will include foundational elements like resource characterization, costs, benefits, and operational constraints, which are important to distribution system planners and operators. Integrating information on flexible loads as a resource is a critical step to provide more visibility of customer-sited resource potential and impacts on transmission and distribution ("T&D") planning and operations.

The specific distribution system benefits that PGE intends to quantify and plan for will be discussed elsewhere, but at a high level, the DRP intends to establish planning methods to understand and value distribution services that require a finer granularity than provision of bulk system services (e.g., energy, capacity). In order to accomplish this, PGE must develop more accurate and well-defined resource characterization for flexible loads.

Local context and resource needs can and do vary throughout the distribution system. To progress towards truly integrated DER planning for distribution system benefit, DRP capabilities must include development of a planning paradigm that seeks to optimize portfolio selection and placement of specific flexible load resources to match specific system needs for different geographic and temporal metrics.

To answer these complex questions for the entire system will undoubtedly take successive iterations of planning rounds, and PGE is committed to developing the analytical framework needed to drive flexible load planning closer to this holistic vision. Because bulk system value can be expected to continue to provide the largest share of system benefits, the quantification of distribution services and locational value will be carried out (at minimum) with the assumption of constrained optimization to balance flexible loads between bulk system and location-specific dispatch. PGE has already begun modeling this for resources like battery storage and will broaden its capabilities to encompass more flexible loads in the course of DSP.

[78] See UM 2005 "Investigation into Distribution System Planning", accessible here: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=21850

[79] See Docket UM 2005, Staff Report, March 13, 2019.
[80] Oregon Public Utility Commission Docket UM 1716
[81] Oregon Public Utility Commission Docket LC 73 (PGE's 2019 Integrated Resource Plan)
[82] Oregon Public Utility Commission Dockets UM 1811, UM 1826, UM 2033
[83] Oregon Public Utility Commission Docket UM 1751 and UM 1856
[84] Oregon Public Utility Commission Dockets UM 1708 and UM 1514

Distribution-sited battery storage is an example of the interdependency between DRP and IRP. In the 2019 IRP, PGE demonstrated potentialities where net cost was negative for distribution-sited battery storage in scenarios where a range of plausible locational values was taken into account (see IRP section 6.4). In the 2019 IRP, this treatment was indicative and drew on past IRP work on energy storage. Going forward, these, and related questions of locational value of DERs, will be addressed by modeling conducted in support of the DRP. Results and assumptions provided by this modeling will be included as inputs to subsequent rounds of the IRP. PGE plans to strategically leverage existing tools and capabilities - and develop new ones where necessary - to ensure that the DSP provides a consistent, transparent, and robust characterization of flexible load and DER resource potential.

3.10 Access to Customer Device Data

3.10.1 Background

PGE's ultimate goal is to support the cost effective and equitable integration of diverse distributed energy resources into our grid. PGE supports the region's goal of decarbonization through smart electricity use, such as transportation and building electrification. PGE continues to support the changing needs of our customers and their use of electricity. Recognizing our role in supporting our customers' priorities and their changing usage, PGE has adopted the strategic imperatives of decarbonization and electrification. This Plan articulates the role of flexible load in achieving these dual goals.

In order for PGE to meet our customer demands, we must integrate, operate, and optimize flexible loads within the distribution grid. This requires PGE to monitor and operate grid-connected devices participating in our programs so that these resources are able to accurately respond to planned and unplanned grid events.

As the planner and operator of the grid, PGE needs to evaluate the results of our programs. This data is needed to ensure that participating flexible loads are optimized across the various grid services, and that PGE is able to capture the data necessary to demonstrate compliance with mandatory reliability standards. Additionally, PGE uses this data to inform effective program design through improved customer offerings and engagement, and also to enhance program performance. The ability to acquire insights from this data is important to our ability to identify, acquire, and optimize ever-increasing levels of DER megawatts.

Generally, device manufacturers provide the software platform - typically via cloud services - that interacts with their devices and provides data to utilities (or DERMs providers, who in turn have utilities as customers) for program operation. Often, these device manufacturers deliver these services through anonymized result data that is generated long after the event has occurred.

PGE seeks a framework that allows utility access to standard device data for program participants who enroll grid-connected devices into PGE programs. Such solutions would be at the customer's direction and agreement; the data would be utilized solely for the purpose of effectively planning and operating the electric grid. [85]

PGE has experienced manufacturer resistance to sharing de-anonymized customer data reflecting specific device usage because device manufacturers often view it as intellectual property and have concerns about their own liability to our mutual customers. If these solution providers experience a change in ownership[86], the terms and conditions governing this data can also change. This complicates PGE's operation and analysis of existing flexible load resources. PGE seeks a solution that enables PGE to access common electric measures as detailed in specifications such as IEEE-1547-2018[87] and IEEE 2030.5[88] for DERs interconnection, with as-close-to-real-time communication as possible, and with the granularly and frequency of which the device is capable. PGE's need for this information is a key requirement for the utility to support our customers' energy journey while developing cost-effective flexible load resources. In making this request, PGE recognizes the inherent commitment to protect customer data, and to follow best practices to protect customer data privacy. PGE accepts its responsibility to keep this data safe and secure while in use, and to ensure that it is not kept beyond its useful life.

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[85] See PGE Advice No 20-46 for the discussion of uses of data in the Multi-family water heater pilot.

[86] For example, when a startup technology is procured by or merges with another company. Such as when Nest was purchased by Google.

[87] Available at https://standards.ieee.org/standard/1547-2018.html The technical specifications for, and testing of, the interconnection and interoperability between utility electric power systems and DERs are the focus of this standard. It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. It also includes general requirements, response to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning, and periodic tests. The stated requirements are universally needed for interconnection of DER, including synchronous machines, induction machines, or power inverters/converters, and will be sufficient for most installations. The criteria and requirements are applicable to all DER technologies interconnected to EPSs at typical primary and/or secondary distribution voltages. Installation of DER on radial primary and secondary distribution systems is the main emphasis of this document, although installation of DERs on primary and secondary network distribution systems is considered. This standard is written considering that the DER is a 60 Hz source.

[88] Available at https://standards.ieee.org/standard/2030_5-2018.html The application layer, with TCP/IP providing functions in the transport and Internet layers to enable utility management of the end user energy environment, including demand response, load control, time of day pricing, management of distributed generation, electric vehicles, etc. is defined in this standard. Depending on the physical layer in use (e.g., IEEE 802.15.4™, IEEE 802.11™, IEEE 1901™, IEEE 1901.2™), a variety of lower layer protocols may be involved in providing a complete solution. Generally, lower layer protocols are not discussed in this standard except where there is direct interaction with the application protocol. The mechanisms for exchanging application messages, the exact messages exchanged including error messages, and the security features used to protect the application messages are defined in this standard. With respect to the Open Systems Interconnection (OSI) network model, this standard is built using the four-layer Internet stack model. The defined application profile sources elements from many existing standards, including IEC 61968 and IEC 61850, and follows a RESTful architecture (Fielding [B3]) using IETF protocols such as HTTP.

3.10.2 Problem Statement

PGE's flexible load plan is dependent on our ability to dispatch connected devices (e.g., smart thermostats, water heater controls, and behind-the-meter batteries). While often subsidized or incented by PGE, these devices are typically owned by the customer and registered for use with the device manufacturer by signing a lengthy list of terms and conditions. These terms and conditions establish an agreement between the manufacturer and the customer about how the data is owned and managed by the manufacturer, including which data points PGE can obtain from the manufacturer, how the data can be used or not used, how it is to be stored, and when the data must be destroyed. This creates a challenge for PGE as this approach not only sidelines PGE's relationship with the customer and their experience, but also effects our flexible load resource development.

3.10.3 Enabling the Best Customer Experience

For PGE to have effective relationships with customers and their devices, PGE must have direct access to the data from these devices.

Fundamentally, for flexible load programs to be successful, PGE requires certain information about when and how each customer participated. This information is correlated to individual event performance, and thus the overall performance of the flexible load resource. As noted in the grid services section, each grid service has specific performance criteria, including some criteria that is auditable under NERC and WECC standards. Data is needed to demonstrate resource performance to inform decision-making in the pursuit of a decentralized, dynamic, and decarbonized grid that continues to operate to the highest standards of safety and reliability. Today, access to and use of this data is controlled by the manufacturers. PGE may only use the data provided in a very limited capacity. Presently, PGE does not have a mechanism whereby the customer can assign data access.

3.10.4 What is Needed

Customers must have the ability to assign access to data directly to a third party such as a utility for use in the deploying and enhancing flexible load programs. PGE seeks to work with the Commission to further define these requirements to support this initiative[89].

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[89] California has addressed this issue with the following language.

> *A business that receives a verifiable consumer request from a consumer to access personal information shall promptly take steps to disclose and deliver, free of charge to the consumer, the personal information required by this section. The information may be delivered by mail or electronically, and if provided electronically, the information shall be in a portable and, to the extent technically feasible, readily useable format that allows the consumer to transmit this information to another entity without hindrance. A business may provide personal information to a consumer at any time but shall not be required to provide personal information to a consumer more than twice in a 12-month period*.

3.11 Demonstration Work in PGE's Smart Grid Testbed

PGE is operating and using the Testbed as envisioned by the Commission and communicated in the Staff whitepaper in docket LC 66.[90] As the following figure shows, PGE is using the Testbed to test and deliver the customer value propositions envisioned and proposed in the PGE Testbed proposal in ADV 859[91] and as requested by Chair Decker in her comments during the Commission meeting approving the Testbed proposal.[92]

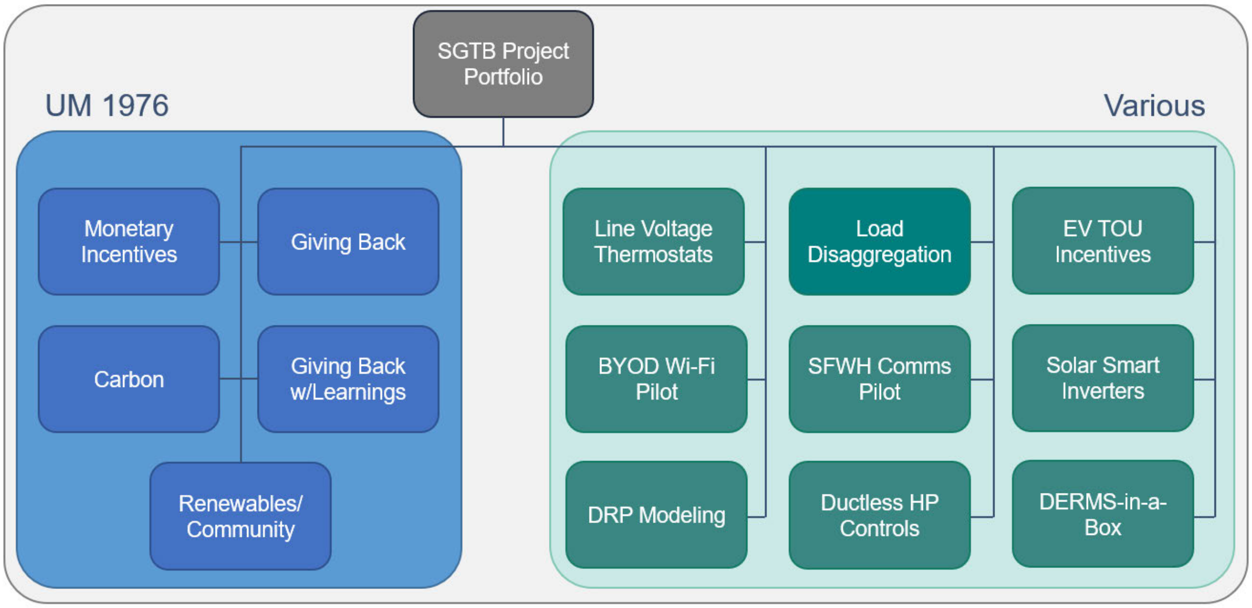

Figure 29 – Smart Grid Testbed Portfolio

The items labeled "Various" on the right side of Figure 29 are demonstration efforts being undertaken within the Testbed based on input from the Demand Response Review Committee. These activities include the following items.

California code: Title 1.81.5, sec 1798.100(d)

This language provides a starting place for an open discussion with the Commission to address data sharing.

[90] LC 66, Staff's Final Comments, Appendix A Demand Response Testbed Overview
[91] Docket No. ADV 859, Advice No. 18-14
[92] Oregon Public Utility Commission, Public Meeting April 9, 2019, where Chair Decker requested PGE conduct work inside the Testbed to advance DER development. Available at https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=387.

3.11.1 DR/DER Locational Value

The PGE Testbed Team is currently working with contractor Kevala Analytics to quantify distribution level value from DR/DER starting with the Island substation in the Testbed.[93] The goal of this work is to help ramp up distribution resource planning activity and refine program cost effectiveness valuations. This work began in Q3 of 2019 and will continue through Q2 of 2020.

3.11.2 Load Disaggregation

The PGE Testbed Team is currently working with contractor Bidgley to conduct a customer asset inventory. PGE is using AMI and building inventory data to predict residential mechanical systems such as home heating and cooling type and water heater fuel type. This work will also provide information on usage patterns and other large loads.

The goal of this work is to help quantify technical DR/DER potential, identify product portfolio roadmap gaps and more effectively target programs and pilots. The work began in Q4 2019 and was completed Q1 2020. We are currently assessing the results of the work and will share the information with the Demand Response Review Committee (DRRC) prior to making a decision to continue with further investment.

3.11.3 Electric Vehicle Time- of-Use Incentives

The PGE Testbed Team is working with the PGE EV Team to conduct research on how time-of-use rate structures affect EV charging behavior[94]. The scope of this work will be to roll out TOU incentives for 400 EVs in the Testbed. PGE will use 100 EVs outside the Testbed as a control group. Contractor FleetCarma will install data loggers in 500 EVs and then enroll these customers in specific Time-of-Use rates over the course of two years.

The goal of the work is to collect information on baseline charging behaviors and vehicle use to inform our understanding of how TOU, event based, and locational value influences charging. The work began in Q1 2020 and will run through Q4 2022.

3.11.4 Communication Study Opportunities

Establishing and maintaining reliable communications with flexible load devices is one of the main challenges with scaling programs and achieving cost effectiveness. PGE's current options for connectivity include cellular, Wi-Fi and local mesh networks. Each of these options has benefits and drawbacks in terms of communications stability, latency, and cost.

PGE is leveraging the multifamily water heaters demonstration to assess the total value of cellular, Wi-Fi and local mesh networks. The demonstration project targets 150 customers to test communication protocols for single family water heaters to inform future pilots and programs. PGE

[93] If successful, this effort will be expanded to the two additional substations in the Testbed, Roseway and Delaware

[94] This work is funded through UM 1826 Clean Fuels.

is partnering with the Energy Trust to identify clusters of heat pump water heaters which have the necessary controls to operate as a DR resource.

The demonstration project is scheduled to launch in later Q2 early Q3 of 2020 and run through Q4 of 2021.

PGE also has an opportunity to study the deployment of local area networks to control Wi-Fi-based control switches as part of a DR demonstration bundle within the Testbed. These utility-owned networks provide a unique opportunity to deploy and test the value of Wi-Fi-based communications for direct load control devices. This project is described in more detail in Section 3.11.8, below.

3.11.5 Energy Efficiency Alignment with Ductless Mini-split Control

Ductless mini-split heat pumps offer another opportunity to expand the types of devices eligible for flexible load program while aligning with EE priorities. Pursuant to Commission Order 19-301 in Docket UM 1696, PGE and Energy Trust are working on a demonstration project to assess the demand response value of ductless mini-split systems.[95] The Energy Trust's goal is to assess whether add on controls can increase EE performance, while at the same time delivering DR/flex load benefit to PGE. Min-split controls research provides an opportunity to explore the measure, while sharing the costs of that activity with Energy Trust.

The demonstration project would launch in Q3 2020 and run through Q3 of 2021, including two cooling seasons and one heating season.

3.11.6 Expanding DR Opportunities with Line Voltage Thermostats

PGE is leveraging one multifamily site in the Hillsboro Test Bed to demonstrate DR controls for line voltage thermostats that are capable of controlling radiant baseboard heat. The 136 units in the Park Village Apartments are all electric and use radiant baseboard systems to heat the units. PGE currently does not have a line voltage thermostat solution in market capable of controlling radiant baseboard heat, nor does it have accurate estimates of the DR value of such controls in our service territory.

As noted above, PGE also has an opportunity to study the deployment of local area networks to control Wi-Fi-based DLC switches. Developing a line voltage thermostat demonstration project at Park Village, enables PGE to explore the flexible load value of this control strategy without the need to deploy a new, dedicated network or rely on those operated by the tenants themselves, thereby reducing pilot costs and improving reliability. Additionally, this project offers an opportunity to test PGE's bundling approach to product development, described in Section 3.3 as this site is also participating in PGE's multifamily water heating pilot.

Due to the Covid-19 outbreak, this project is on hold until such time as PGE and Park Village Apartments are able to reconnect regarding installation or an alternative site can be established.

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[95] Commission Order 19-301, Docket UM 1626, available at https://apps.puc.state.or.us/orders/2019ords/19-301.pdf.

This project may be pushed to a potential Phase II if market conditions continue to present installation barriers.

3.11.7 Leveraging the Capability of Smart Inverters

Smart inverter capabilities currently exist on many inverters already interconnected into PGE's distribution system. With the passing of IEEE1547-2018,[96] it is reasonable to expect that Oregon will soon adopt the standard and all new smart inverters will adhere to the standardized functionality and control prescribed in IEEE1547-2018. This availability will pave the way for a more streamlined process for utilities to access and utilize smart inverter features. Smart inverter capabilities include voltage regulation, frequency support, and relief of distribution constraints through direct load control.

Conducting a smart inverter demonstration in the Testbed provides PGE an opportunity to test the effectiveness of these functions on a small scale, limited duration basis. This project will also inform a potential future regulatory requirement and provide insights into how smart inverter settings can be optimized to meet the needs of our system.

The Testbed team has engaged in preliminary conversations with the Energy Trust of Oregon and secured a list of existing interconnections in the Testbed that can be enabled. The timing of launch would be contingent on the development of a tariff (or modification of Sch. 13), contractual negotiations, and associated IT processes (e.g. security screening) related to the inverter original equipment manufacturers (OEMs). This projects status is placed on hold until a market approach can be identified. The current market is challenging due to Covid-19 restrictions.

3.11.8 Bring Your Own Device

The PGE Testbed team is working with contractor Virtual Peaker on a Bring Your Own Device demonstration project in the Testbed. Virtual Peaker has established appliance cloud-based controls with a host of companies such as General Electric, Rheem, Honeywell, Chargepoint and others. The demonstration project seeks to deploy a flexible DR/DER program platform to test new technology and program design.

The goal of the demonstration project is to evaluate the grid value of a "bring your own" DR program structure that covers a range of Wi-Fi based DR technologies. The idea is to test the viability of a device agnostic flexible load program which pays participants based on the service they can provide to the grid. This demonstration project is the first step in understanding how to develop a platform like approach to flexible load.

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[96] The technical specifications for, and testing of, the interconnection and interoperability between utility electric power systems (EPSs) and distributed energy resources (DERs) are the focus of this standard. Available at https://standards.ieee.org/standard/1547-2018.html

PGE and Commission Staff discussed this approach in June 2020. At that time it was decided that a Bring Your Own Device approach is complex and would require additional work on PGE's part and additional conversation with regulatory Staff.

3.11.9 Distributed Energy Resource Management System

A standalone Distributed Energy Resource Management System or DERMS solution with a preliminary Optimal Power Flow model offers a multifaceted opportunity to advance PGE's ability to build the Virtual Power Plant.

PGE is partnering with Open Systems International, Inc. (OSI) to build a DERMS that can model power flow for the three Testbed substations (Island, Roseway and Delaware). OSI also provides PGE's Energy Management System (EMS) that supports PGE's bulk electric activities, including automated generation control and integration with the Energy Imbalance Market. PGE hopes to leverage integration opportunities available across the OSI platform to provide both bulk electric and distribution level grid services. This integrated approach will allow PGE to maximize the value of the distribution cited Virtual Power Plant in ways that would not be available without system integration.

The goal of the demonstration project is to evaluate the flexible load opportunity, to capture the capacity value of DR, to establish distribution deferral values, to determine local distribution power losses, and to identify tools for reducing losses. The demonstration project will enable PGE to improve the management of both front of the meter and behind the meter flexible loads including distributed generation (DG), energy storage, DR, and EVs.

The demonstration project leverages existing work done for ADMS and data from PGE's geographic information system (GIS) for Testbed circuits. Additionally, the demonstration work with a discrete DERMS will enable PGE to integrate multiple Testbed elements into a demonstration Virtual Power Plant.

This demonstration project is expected to launch in Q3 2020 and run through Q1 2021.

Chapter 4 Cost Effectiveness

Chapter Summary

Chapter 4 is not a request for action from the Commission, but rather a recitation of our cost effectiveness practices. This chapter also defines and discusses the various grid services that flexible load does, or may be able to, provide in the future. This chapter is offered for transparency and to demonstrate the maturity of our practice in identifying and validating flexible load values and cost effectiveness.

4.1 Introduction

This chapter lays the foundation for conversations with the OPUC around measuring flexible load cost-effectiveness. It first focuses on the cost effectiveness methodology in place today, and then discusses the current status of the portfolio and actions being taken to improve portfolio results.

The value of flexible load will continue to grow as our grid rapidly transforms into a decentralized, low-carbon energy system; flexible load is a vital component in meeting our decarbonization goals. Along with growing and improving our flexible load portfolio, PGE is building the quantitative analysis to support this investment. We are pursuing improvements in both programs and quantitative evaluation simultaneously. Program development and refinement, market adoption, and participant education is a multiyear journey, and only through sustained commitment will this resource be ready for our transforming electrical system. PGE recognizes that successful demand response programs share a common feature: consistent, sustained commitment to the resource over time. PGE is committed to building and maintaining flexible load resources that mature into long-running programs. PGE looks forward to Staff's partnership in both program evolution and cost effectiveness evaluation.

4.2 Regulatory Background

The OPUC adopted the current cost effectiveness methodology in 2015 through Commission Order 15-203 (UM 1708)[97]. This approach is based on California protocols, now updated via its Standard Practices Manual[98]. In April 2016, PGE submitted *A Proposed Cost Effectiveness Approach to Demand Response* to the OPUC outlining this methodology[99]. The 2016 proposal, prepared by Navigant, was informed by PGE's unique system, stakeholder feedback, as well as Navigant's 2015 work on BPA's *Smart Grid Regional Business Case*. Beginning in 2015, each pilot filing has included a cost effectiveness forecast based on the California protocols.

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[97] Commission Order 15-203, UM 1708, PGE Compliance Filing April 28, 2016, "A proposed Cost Effectiveness Approach for Demand Response."
[98] 2016 Demand Response Cost-Effectiveness Protocols, California Public Utility Commission, Available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11573
[99] Commission Order 15-203, UM 1708, PGE Compliance Filing April 28, 2016, "A proposed Cost Effectiveness Approach for Demand Response."

Since its first analysis, PGE has grappled with appropriate value assignment and which of the four tests is most applicable. The cost effectiveness analyses accompanying PGE's pilot filings in Appendix A reflect this ongoing analytical work. System values are updated as our understanding of flexible load products, deployment, and impact evolves. The California protocols are applied to all flexible load pilots and programs, populating the values applicable to each specific application. In February of 2020, Commission Staff commented on the Company's IRP and provided three recommendations on cost-effectiveness for DR, below[100]. Each recommendation is explored within the chapter's discussion of current practice. The location of that discussion is identified below each recommendation:

- **Staff recommendation 1:** The use in all calculations of the same base values as those employed for EE, specifically found in UM 1893.

  FLP location: The distinction between EE and flexible load, and the historic basis of their distinct valuation, is discussed in section 4.3.3.

- **Staff recommendation 2:** Reflect the benefit of DR as a zero-emission, dispatchable capacity resource. One such method could be to assign DR a capacity value equivalent to a non-emitting, dispatchable resource, not the current proxy resource.

  FLP location: Capacity resource selection and impact is discussed in section 4.3.2 of this chapter.

- **Staff recommendation 3:** Discontinue the use decrementing value assumptions that assume a value of lost service until PGE has the data to establish such a penalty.

  FLP location: Value of lost service assumptions and impact is discussed in section 4.2 of this chapter.

In April of 2020, Commission Staff requested that the Company provide data comparing DR avoided costs to the Commission Order No. 19-430 avoided cost methodology for energy efficiency[101]. Subsequently, in May of 2020, the Commission highlighted the importance of PGE's Flexible Load Plan to "sufficiently advance stakeholder understanding of PGE's approach to demand-side resources as a comparable resource to supply-side capacity".

This chapter seeks both to advance stakeholder understanding and to lay the foundation for ongoing collaboration.

4.3 Current Practice Inventory

Chapter Two describes how DERs have been treated within IRP system planning to date: cost effectiveness has been determined exogenously, by a third-party consultant, and reflects generic

[100] Staff's Final Report LC 73 Docket LC 73 PGE's 2019 IRP at p. 14 available at https://edocs.puc.state.or.us/efdocs/HAU/lc73hau163412.pdf.
[101] OPUC Information Request 001, Dated April 10, 2020 providing table from Order No. 19-430 in Docket UM1893.

program cost and benefit assumptions. Forecasted MW of flex load adoption has also reflected these generic assumptions. At the program level, in contrast, program design attempts great specificity in the costs and benefits unique to each program, and these details are reflected in the program-specific cost effectiveness results. As PGE gains experience with flexible load deployments, inputs are refined to reflect the costs and load impacts realized.

The OPUC and PGE has emphasized the Total Resource Cost (TRC) Test result in its pilot filings. The TRC test is expressed as a single benefit-to-cost ratio, and necessarily describes a snapshot in time. For programs in flight, ratios reflect both past actuals and projected future conditions over the anticipated program life. This is expressed as a single dollar amount on a net present value basis. The snapshot reflects:

- Past enrollment + future enrollment assumptions;
- Past costs realized + future cost assumptions;
- Current load impact + future load impact assumptions, if expected to change, and
- System benefits values as modeled per IRP

4.3.1 PGE’s Flexible Load Cost Effectiveness Framework: Four Perspectives

PGE’s analytic approach to cost-effectiveness is based on Commission Order 15-203 and California protocols, now updated via its Standard Practices Manual[102]. A cost-effectiveness test measures whether an investment’s benefit exceeds its cost and is one tool in ensuring that PGE makes well-informed investment decisions. Typically, a cost-effectiveness test calculates the net present value (NPV) of both benefit and cost streams over the post-pilot lifetime of the program. The result is presented as a benefit-to-cost ratio.

Since investments are often “lumpy”, cost effectiveness measurements require a forecast of both costs and benefits over the life of the program. For instance, some programs have substantial start-up costs such as initial equipment investment or IT enablement. For in-flight pilots and programs, PGE’s application of the cost effectiveness tests includes both realized results and future estimates, including program enrollment assumptions.

Historically, the primary benefit stream associated with flexible load programs has been the avoided cost of capacity. PGE continues to explore and quantify values beyond capacity as technology improves and costs decline. The primary cost streams are equipment purchases, program implementation costs, and incentive payments.

PGE employs a four-test framework common throughout the country. Each provides a distinct stakeholder perspective and includes a distinct set of benefit and cost streams. The four tests are

[102] 2016 Demand Response Cost-Effectiveness Protocols, California Public Utility Commission, Available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11573

the Total Resource Cost (TRC) test, the Program Administrator Cost (PAC) test, the Rate Impact Measure (RIM) test, and the Participant Cost Test (PCT).

4.3.1.1 Total Resource Cost Test

The TRC adopts a summary perspective for all stakeholders: the utility and its customers. While not a full societal test – which might attempt to quantify externalities such as the health impacts of carbon – the TRC attempts to holistically answer whether the program's benefits justify its costs. This test is widely accepted by the stakeholder community and has been emphasized in PGE's pilot DR filings to date.

Because the TRC strives for a holistic lens, it excludes transfers between the utility and its customers; a benefit to one party is a cost to the other, and they cancel one another out. These transfers include incentive payments, bill savings, and bill increases.

The second noteworthy element of the TRC is the inclusion of participant cost categories: Transactional Cost to Participant (dollars spent to enable participation) and Value of Service Lost (quantification in dollars any inconvenience a customer may experience during a DR event).

4.3.1.2 Program Administrator Cost Test

The PAC test measures the net benefits of a program from the perspective of the program implementer, in this case, PGE. All financial costs borne by the administrator are included, including participant incentive payments. The customer's Transactional Cost and Value of Service Lost are excluded.

The PAC test reflects the perspective of the program administrator as a financial entity. A program that achieves a benefit to cost ratio of 1.0 will reduce costs for that entity. For a Cost of Service utility such as PGE, this means reducing customer costs.

4.3.1.3 Rate Impact Measure Test

The RIM test measures the net benefits of a program from the perspective of non-participating customers. It is largely similar to the PAC test, but includes decreased energy sales as a cost, and increased energy sales as a benefit. If a program achieves a 1.0 benefit-to-cost ratio on the RIM test, its benefits outweigh its costs for non-participating customers. A result less than 1.0 indicates that cost shifting will occur.

As part of UM 2003, PGE submitted a cost-effectiveness methodology for EV programs based on the RIM test. EV programs by themselves are not flexible load programs. However, some EV programs have an associated grid services program. Like other EV programs, these EV DR program are evaluated using the RIM test.

4.3.1.4 Participant Cost Test

The PCT test measures the net benefits of a program from the perspective of customers participating in DR programs. Program costs and energy system benefits are excluded; only

Transactional Cost to Participants and Value of Service Lost are included as costs; incentives are included as benefits.

4.3.2 Test Elements

Table 5, compares the cost and benefit streams included in the different cost-effectiveness tests. Each category is then discussed in more detail.

Table 5 – Cost and Benefit Streams of Cost Effectiveness Tests

Cost/Benefit Category	Total Resource Cost (TRC) Test	Program Administrator Cost (PAC) Test	Rate Impact Measure (RIM) Test	Participant Cost Test (PCT)
Administrative costs	Cost	Cost	Cost	
Avoided costs of supplying electricity	Benefit	Benefit	Benefit	
Bill Increases				Cost
Bill Reductions				Benefit
Capital costs to utility	Cost	Cost	Cost	
Capital costs to participant	Cost			Cost
Environmental benefits	Benefit			
Incentives		Cost	Cost	Benefit
Increased supply costs	Cost	Cost	Cost	
Revenue gain from increased sales			Benefit	
Revenue loss from reduced sales			Cost	
Transaction costs to participant	Cost			Cost
Value of service lost	Cost			Cost
Categories not currently utilized:				
Market benefits	Benefit	Benefit	Benefit	
Non-energy/monetary benefits	Benefit			Benefit
Tax credits	Benefit			Benefit

4.3.2.1 Benefit Categories

The system benefits of flexible load are largely determined through modeling. Inputs and assumptions that drive this modeling are regularly updated via the IRP and other dockets, which leads to fluctuations in value. Programs do not determine these values; the values are inputs to which program design and management must respond. PGE recognizes that building successful, mature flexible load programs requires consistent, sustained investment even as these values fluctuate. Over time, PGE intends that our investments in flexible load are cost effective.

Avoided Cost of Supply Electricity is the largest category of benefits. As PGE moves down the pathway to decarbonization and electrification, our need for these services will increase[103]. Flexible load is a key source for these grid services, as evidenced by the findings in PGE's "Pathways to Deep Decarbonization" Study. As technology advances and costs decline, flexible load's role in providing these services will grow. Services will expand as flexible load's ability to provide grid services evolves, along with PGE's ability to model the financial value of those services.

For PGE's existing portfolio, the largest value stream currently is capacity, which reflects the historic design intent of DR and the capital-intensive nature of new generation. The valuation of capacity is established in PGE IRP dockets, and also outlined in the California Standard Practices Manual.

The following sections provide detail on benefit categories.

4.3.2.2 Avoided Cost of Capacity

The value in the avoided cost of capacity is derived from flexible load's ability to contribute to Resource Adequacy (RA). RA is deliberately planning one to four years ahead to ensure there are enough resources – generation, efficiency measures, and DR including flexible load – to serve loads across a wide range of conditions with a sufficient degree of reliability.[6] The value of reliable capacity continues to grow as the region sees increasing thermal plant retirements, limited available long-term transmission capacity, and the expansion of new loads[104].

Capacity needs typically cluster in certain seasons and hours in which demand for electricity is highest and resource availability[105] is limited. As the penetration of variable energy resources (VER) grows, PGE may see emerging capacity needs for periods when renewable supply is limited. In some ways, a capacity product is like an insurance policy: its value does not derive from its use, but from the policyholder's ability to call on it if necessary. Because of this, a capacity product with limited availability (such as some forms of demand response) can be useful when its availability aligns with periods of system constraint.

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[103] These services include regulation and frequency response; reactive supply and voltage control; and contingency reserves. These services are described in detail in this chapter.
The grid service section of this chapter reviews the possible grid services flexible load might be capable of providing.

[104] This approach is similar to that employed by the Northwest Power and Conservation Plan Seventh Power Plan where the Resource Plan therein called for the development of 600MW of demand response by 2021 to satisfy regional resource adequacy standards and meet additional winter peaking capacity. Here the Power Council found that, "The least-cost solution for providing new peaking capacity is to develop cost -effective demand response resources the voluntary and temporary reduction in consumers' use of electricity when the power system is stressed." Seventh Northwest Conservation and Electric Power Plan, Chapter 1: Executive Summary, available at https://www.nwcouncil.org/sites/default/files/7thplanfinal_chap01_execsummary_6.pdf.

[105] For example, hydroelectric resources may be de-rated in late summer.

PGE models the value of capacity as the long-term avoided cost of acquiring a capacity resource. The identification of this resource (the 'proxy resource') and its costs are determined via PGE's IRP process. In the 2016 IRP, the generic capacity resource was identified as a Simple Cycle Combustion Turbine and valued at $131.11/kW-yr (2020 dollars)[106]. This value is held consistent across a variety of dockets and pricing mechanisms.

Flexible load varies from the proxy capacity resource in important ways, including:

- Frequency with which the resource can be called;
- Days and hours in which the resource is available;
- Number of consecutive hours it is available; and
- Whether energy is avoided or shifted.

These differences typically decrease the value of capacity that a use limited resource such as a VER or flexible load, brings to the system relative to the proxy capacity resource. In 2019, PGE began modeling DR programs to quantify (rather than estimate) a DR Effective Load Carrying Capacity (ELCC). This modeling is done via the Renewable Energy Capacity Planning Model (RECAP).

Prior to 2019 RECAP modeling, PGE estimated the capacity value of DR through a series of five adjustment factors in alignment with the California Public Utilities Commission. Those adjustment factors will be familiar to DR stakeholders.

All of PGE's current DR pilot proposals initially utilized estimated adjustment factors. 2019 modeling resulted in an increased ELCC for some programs (meaning a smaller adjustment or de-rate), and a decreased ELCC for others. Across the portfolio, pilot proposals estimated an average ELCC of 72%. RECAP modeling resulted in a lower portfolio average ELCC of 60%. RECAP modeling will be refined over time, as program characteristics - such as the extent that energy is shifted rather than reduced - are better quantified based on PGE's operational experience.

Table 6 – Pilot Assumption and Modeled ELCC across the Flexible Load Portfolio

Pilot Proposal	2025 MW Target	Pilot ELCC	Modeled ELCC
Time of use	19	100%	90%
Water heaters	22	82%	73%
Electric vehicles	16	100%	79%
Energy Partner	30	44%	63%
Thermostat	74	77%	60%
Peak Time Rebate	26	42%	44%
Portfolio	186	72%	65%

[106] Current programs were designed to meet the 2016 IRP objective of 77 MW in winter by the end of 2020, and initially profiled with 2016 IRP values. We have held those values steady within this document.

The complete calculation for a program's annual capacity value is as follows:

Cost of proxy resource	X	Program-specific ELCC	x	Load reduction per enrollee	x	Number of enrollees	X	1+ T&D peak line loss

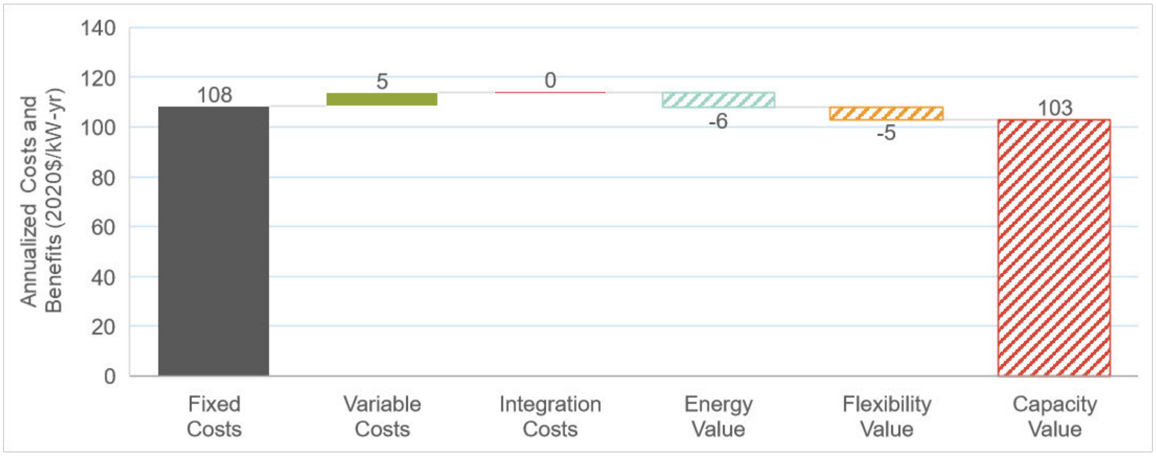
For a single Thermostat DR customer, this looks like:

$131/kW-yr	X	60%	X	0.80 kW-yr	X	1	x	1.08	=	$67.97

This is the annual capacity value of a single, two-season thermostat DR participant to PGE's system (in 2020 dollars; value inflates annually). A benefits-based budget would use this value as a cap on program expenditures (for thermostats, 98% of program value is capacity).

Staff recommendation: Reflect the benefit of DR as a zero-emission, dispatchable capacity resource. One such method could be to assign DR a capacity value equivalent to a non-emitting, dispatchable resource, not the current proxy resource.

In LC 73, Staff recommended that PGE explore the use of a non-emitting capacity resource to value the capacity provided by demand response and flexible load programs. PGE appreciates this recommendation and provides additional information here to inform future discussions about evaluating the capacity value of demand response and flexible load programs. First, it is important to consider that the cost of capacity is intended to reflect the cost that PGE and PGE customers would otherwise incur to specifically provide an equivalent amount of capacity to the system, which is separate and distinct from potential benefits associated with avoided emissions or other attributes of a flexible load. The benefits associated with avoided emissions are captured within the energy value of each program, to the extent that the forward energy prices used in that determination incorporate a price on carbon, as is the current practice in the IRP. To isolate these types of benefits from the value of capacity, PGE calculates the net cost of capacity from a proxy capacity resource by subtracting all non-capacity benefits from levelized cost of the proxy resource, as shown in Figure 6-7 in the 2019 IRP.



From PGE's perspective, the question that Staff raises is not necessarily about the non-emitting nature of the proxy resource but is instead about the alignment of the proxy capacity resource with the actions that PGE would otherwise be taking specifically to meet capacity needs. PGE's 2019 IRP Action Plan lays out the Company's plan to secure capacity that is not provided by flexible loads through a combination of bilateral negotiations for existing resources in the region and through a non-emitting capacity RFP or RFPs[107]. The outcomes of these competitive processes provide a better indication of true avoided costs than the estimates provided in the IRP, especially when the proxy resources in the IRP rely upon technologies with rapidly evolving costs, such as renewables and battery storage.

The IRP necessarily estimates costs associated with capacity resources several years in advance in order to inform a robust long-term plan. In the 2019 IRP, cost estimates for energy storage in 2025, the year of focus for PGE's capacity acquisitions, were developed in 2018, seven years before those resources would potentially come online. To address this time lag, the IRP considers wide ranges of potential costs. For example, the 2019 IRP estimates that annualized fixed costs for a 6-hour battery in 2025 could fall below $150/kW-yr or could exceed $250/kW-yr.

While it is necessary and important that long term planning considers market estimates with wide ranges of uncertainty when technology costs are evolving so quickly, these estimates do not lend themselves well to direct application in tariffs, cost effectiveness evaluations, and other decisions and determinations that have an unfiltered impact on customer prices. This filtering occurs when the Company conducts a competitive solicitation for a specified need to determine the actual cost of these technologies in the market and whether those costs are aligned with the interests of our customers.

PGE is open to Staff's suggestion to consider non-emitting resources when valuing the capacity provided by flexible load to the extent that such consideration focuses on the outcomes of recent

[107] The acknowledged 2019 IRP Action Plan describes two RFPs, which, per Order 20-152, must allow for co-optimization between them or be combined into a single RFP. At this time, PGE has not put forward an RFP design proposal.

competitive solicitations and allows for frequent updates as technologies mature, rather than the infrequent and time-lagged estimates as currently provided through the IRP.

4.3.2.2.1 Avoided Cost of Energy

If a Flexible Load program results in net energy savings, the value of that energy is considered a benefit. Many flexible load programs involve minimal energy reduction: DR programs may operate less than 50 hours per year, and they may *shift* energy rather than *reduce* overall energy consumption. Energy is therefore typically a far smaller component of the benefit stream.

Energy is valued at PGE's long-term wholesale energy forecast, Aurora. Programs are attributed with avoiding the on-peak cost under the carbon pricing forecast scenario. For some programs, energy cost estimates target the months and hours the program is available. In today's DR portfolio, energy is less than 5% of the program benefit. For emerging flexible load such as batteries and electric vehicles, with their greater call frequency, energy may be a more significant benefit stream.

4.3.2.2.2 Avoided Cost of Transmission & Distribution

Several Grid Services are described in Section 4.4.1, below. To date, PGE's flexible load programs have not been administered to provide PGE with grid services. PGE will explore grid services as program deployment and operations stabilizes and matures, and for those programs with appropriate attributes (such as direct load control). The behind-the-meter residential battery and water heater pilots will likely be the first pilots to supply grid services.

Additionally, as discussed in Chapter 2 on the DRP, PGE's investment in ADMS and ongoing R&D efforts will inform the valuation of distributed flexibility in providing grid services such as volt var and reactive power. PGE plans to include T&D value streams as they become available via R&D efforts that pursue both the technical application and the quantification of financial value.

Broadly speaking, the most commonly applied T&D value in utility pricing has been the avoided cost of infrastructure investment. This value is applied to Energy Efficiency per PGE's Marginal Cost Study. For flexible load, PGE's current working proposal is that programs should be credited with T&D deferred investment under the following conditions:

- A specific transmission or distribution system constraint has been identified;
- The cost of and required timeframe for the traditional solution has been estimated;
- The non-wires alternative is deemed capable of deferring or avoiding all, or a portion of, the traditional investment;
- If deferred, the timeframe associated with the deferral has been estimated; and
- Results are unitized: e.g. a non-wires alternative that solves half of the need is attributed with half of the cost/value of the traditional solution.

The necessary correlation to attributing flexible load programs with deferred or avoided capital investment is to reduce capital investment. PGE is working towards applying this lens consistently and holistically in its product development and capital investment processes.

4.3.2.2.3 Avoided Cost of Flexibility Services

Flexibility services encompass generation system needs other than energy and capacity, specifically, Contingency Reserves and Regulating Reserves. As described in Section 3.3.2 flexible loads with response times that meet specific integration, communication, and performance criteria can provide flexibility services. PGE includes these values when appropriate and expects flexible load to provide more flexibility services as technology improves, costs decline, and PGE's need increases.

4.3.2.2.4 Environmental Benefits

The TRC is the only test where environmental benefits are highlighted. PGE has quantified this value as the cost of carbon in energy prices. This was done by modeling the difference between two scenarios in the Aurora forecast: the "with-carbon-pricing" scenario; and the "without-carbon-pricing" scenario. The cost of carbon is applied on a per MWh basis. Because many flexible load programs have minimal energy impact, the modeled environmental benefit of those programs is also minimal.

The 2016 Navigant/PGE white paper describes additional benefits beyond carbon pricing, including reduced emissions of sulfur dioxide, nitrogen oxides, and particulate matter[108].

4.3.2.2.5 Bill Reductions

Bill reductions are included as a benefit within the Participant Cost Test. Reductions typically correlate to total energy consumption, which has been noted as minimally impacted by most existing flexible load programs. Bill reductions are directly related to the number of events called, the customer's participation in each event, and the incentive structure. These bill reductions are generally, inconsistent dependent on grid conditions requiring an event be called. Exceptions include the in-flight Time of Use pricing proposal, which has the potential to produce persistent customer bill savings.

4.3.2.2.6 Lower Per-Unit Costs from Increased Sales

Within a certain bandwidth this is the inverse of bill reductions and can be a benefit from the ratepayer's perspective. For a Cost of Service utility, there are certain fixed costs[109] that must be collected from all customers. While some of these costs are collected through basic service charges, the majority of these costs are collected through volumetric charges on a per-kWh basis. As a utility's customer base (sales in kWh) grows, these fixed costs are spread across more customers, lowering the per-unit cost of service. In other words, increased sales grow the denominator (kWh) across which system costs are spread. For a Cost of Service utility, increased usage increases can lower customer prices assuming the increasing load does not require

[108] UM 1708 PGE's Application for Deferral of Expenses Associated with Two Residential Demand Response Pilots, April 28, 2016 Compliance Filing, A Proposed Cost -Effectiveness Approach for Demand Response, at Page 11. Available at: https://edocs.puc.state.or.us/efdocs/HAD/um1708had113843.pdf.

[109] For example, substation equipment; transmission and distribution lines; fixed costs of generation.

additional investment above the increase to revenue. An example of this is flexible load partnered with transportation electrification, which has the potential to measurably increase electricity sales while spreading fixed costs across a greater volume of sales.

4.3.2.3 Cost categories

Program costs are the primary lever with which program management can impact cost effectiveness and are the focus of deferral filings and program reporting. The following sub-sections provide detail on cost categories.

4.3.2.3.1 Administrative Costs

Administrative costs encompass all costs to run a program other than capital costs and incentives. They are included in all tests except the Participant Cost Test. Administrative costs typically include:

- Program marketing and management
- Program evaluation
- Distributed Energy Management Systems
    - Platform provisioning
    - Data costs
    - Equipment manufacturer licensing costs
    - One-time integration costs
- Data network costs, if not included in above
- Third-party administrator, if applicable

With a continually evolving understanding of program and customer needs, PGE is actively managing administrative costs and contracts across the portfolio to improve cost effectiveness. The Flexible Load Plan represents PGE’s proposal to measurably reduce administrative costs.

4.3.2.3.2 Capital Costs

PGE distinguishes capital costs from O&M in alignment with California protocols. The significance of this distinction lies with utility budgeting: O&M and capital typically have distinct budgeting processes, and capital requires more nuanced forecasting to model its impact on annual revenue requirement. Under Generally Accepted Accounting Principles (“GAAP”), capital describes an investment in which the asset life is greater than one year; recovery of that investment is thus spread over more than one year in alignment with the useful life of the asset. The undepreciated portion of a capital investment appears on the utility balance sheet. In the Cost of Service regulated model, capital investment is also the mechanism by which shareholders earn a return.

To date, DR programs have included minimal capital investment. An exception is the IT investment required to support Peak Time Rebate data integration. When PGE contributes to the purchase of a long-lived asset but does not retain ownership (e.g. Energy Partner investments or Thermostat Direct Install), the purchase is expensed.

Cost effectiveness modeling incorporates both program administrator capital investment and program participant capital investment. For the program participant, PGE interprets this as a capital investment required for participation in the flexible load program. For instance, for Bring Your Own thermostat DR, the participant's purchase of the thermostat is not included. This is because the thermostat serves a primary role of regulating heat; it was not purchased primarily to enable DR program participation.

4.3.2.3.3 Incentives

Incentives are the financial payment to participants and are included in all tests other than the TRC test. In the TRC, incentives are considered a transfer payment and thus excluded. Incentives can be structured in a variety of ways, including a per-season, per-event, or per-kWh basis. Some incentives are up-front to encourage customers to join a program. Others are on-going payments designed to encourage continued participation in events. PGE incentive levels were developed through national review of similar programing, market research, PGE system values, and pilot results, and can be adjusted if deemed necessary through tariff updates. For PGE's current DR portfolio, incentives range from 30-50% of annual programs costs.

4.3.2.3.4 Transaction Costs to Participants

This captures any dollar cost to the participant. PGE does not currently utilize this cost category, as programs have been designed without this requirement. To date, any investment that programs that require – such as a thermostat – has a primary purpose other than enabling DR participation.

4.3.2.3.5 Value of Service Lost

This is a qualitative cost intended to capture the inconvenience of participating in a flexible load program. It attempts to translate into dollars the customer experience of a turned-down air conditioner on a hot summer night, or an industrial process curtailment. It appears in the TRC and PCT only. Per the California Protocol, PGE has calculated this value as a share of the incentive the participant receives, under the theory that if the value of service lost exceeded the incentive, the participant would leave the program. The TRC looks at costs and benefits across the utility and the program participant. Loss of service is a new "cost" introduced by the flexible load program, and, as such, the TRC attempts to capture its impact.

Because the Value of Service Lost is a subjective measure, PGE applies it generically according to program type, as do other utilities. PGE assigns this value according to three levels of customer impact:

- No intended service level impact: lost service = 10% of incentive value
- Residential program with service level impact: lost service = 25% of incentive value
- Commercial program with service level impact: lost service = 50% of incentive value

The impact on TRC results varies by program, as illustrated below (all dollars are in millions, on 10-year NPV basis):

Table 7 – Impact of Test Results by Program

	Total Program Cost	Incentive Cost	Value of Service Lost	Resulting TRC Cost Reduction	B:C Ratio Impact
No intended customer impact					
Water Heater	$26.42	$11.86	10%	$11.86 x (1-10%) = $10.86 cost reduction	+37%
Visible customer impact (residential)					
PTR	$24.11	$10.77	25%	$10.77 x (1- 25%) = $8.08 cost reduction	+50%
Visible customer impact (commercial)					
Energy Partner	$20.90	$12.55	50%	$12.55 x (1-50%) = $6.28 cost reduction	+30%

PGE originally adopted this cost line item in alignment with the California protocol. It has retained its use because it brings TRC test results into closer alignment with the PAC and RIM tests. The table above shows the impacts of the value of lost service on the TRC test. Without the Value of Service Lost, the TRC lens would be less balanced giving outweighed affect to incentives calculated in the participant cost test. With the Value of Service Lost in place a better balance is struck.

Staff recommendation: Discontinue the use decrementing value assumptions that assume a value of lost service until PGE has the data to establish such a penalty.

PGE agrees that the decrementing value assumption is not grounded in research. However, the decrementing value assumption does bring the results of the four tests into closer alignment. One alternative PGE has considered is utilizing the Test Bed to conduct research on program-specific Value of Service Lost for our customers. Because the TRC excludes the cost of incentives, it produces significantly (30-50%) higher ratios that the PAC and RIM tests, even with the Loss of Service adjustment. PGE has continued to use Value of Service Lost because it is an established part of the TRC test and it brings the tests into closer alignment, as PGE internally focuses on the RIM in order to reduce customer cost shifting. This is however a suboptimal solution.

PGE recognizes that cost effectiveness is evolving both regionally and nationally; PGE is monitoring these conversations and is interested in continued dialogue with the Commission and Staff. For instance, a National Standard Practice Manual is in its final stages of development, sponsored by a consortium of groups, that attempts to evolve the California standards and allow for tailoring to each jurisdiction's circumstances and priorities. PGE supports the transparent treatment of all costs and benefits associated with flexible load and looks forward to continued exploration in this area.

4.3.2.4 Test Elements Not Utilized

The following categories were included in the 2016 Navigant white paper and reflect the national landscape review that supported that work. Oregon's market conditions and PGE program/market data do not support the current inclusion of these categories in our cost effectiveness analyses. They are included in this document for awareness and can be rolled into test results should conditions change.

4.3.2.4.1 Organized Wholesale Market Benefits

This benefit depends upon a competitive wholesale capacity market typically operated by an Independent System Operator (ISO) or a Regional Transmission Organization (RTO). As such, it is currently not used. The 2016 Navigant/PGE white paper describes this benefit as follows:

This category of benefits includes increased market efficiency improvement in overall system load factors and improved market performance (e.g., decreasing price volatility). This benefit is often quantified as the price elasticity of demand market price effect, also known as demand reduction induced price effect (DRIPE).

In competitive electricity markets, lower demand for capacity yields lower overall prices. Therefore, a significant load reduction can have the effect of suppressing market capacity prices for all parties participating in the market. This price suppression is a benefit to all market participants, separate and additional to the avoided cost of capacity for a particular utility administering the DR program.

A competitive capacity market is a prerequisite to realizing any DRIPE benefits from DR, as well as a having a critical mass of DR resources in the market.

PGE notes that the Northwest Power Pool has undertaken an effort to establish a Regional Resource Adequacy program. This effort is examining the capacity contribution of flexible load and other emerging technologies as part of this effort[110]. PGE supports the inclusion of flexible load as an RA capacity resource and is actively participating in program development.

4.3.2.4.2 Non-Energy and Non-Monetary Benefits

Non-monetary benefits include participants' perception of helping to protect the environment, being good citizens through grid-engagement, improving their ability to manage their own energy usage, having a better public image (for commercial enterprises), and improving working conditions. This is a qualitative benefit that is difficult to quantify. PGE has not assigned this benefit to its flexible load offerings to date. In states such as California and Hawaii, it is included in the TRC test only.

While many people intuitively believe that these perceptions influence participation, they are difficult to quantify. In many ways this is a qualitative corollary to Value of Service Lost.

[110] https://www.nwpp.org/adequacy

Participant interviews or surveys could provide a basis for including this benefit stream in the future. However, in the past, the Commission has not allowed non-energy benefits to filter into cost benefit calculation for customer programs such as energy efficiency.

4.3.2.4.3 Tax Credits

Oregon does not currently use tax credits for flexible load. HB 2618, passed in 2019, provides $30 million to the Oregon Department of Energy to create a program for providing rebates for the purchase, construction or installation of solar electric systems and paired solar and storage systems. These incentives may be included in future flexible load programs.

4.3.3 Flexible Load vs. Energy Efficiency

EE cost effectiveness protocol was first established with the Power Act and has had decades of stakeholder review and engagement. It is often suggested as a basis for or comparison to flexible load modeling. EE is a demand side program as is flexible load; however, the impact of EE on PGE's system is more straightforward, particularly for permanent load reductions which lower the demand curve in every hour[111]. In contrast to flexible load, energy efficiency is not designed to respond to shifting system conditions, and it is not deployed.

Because EE reduces the total volume of system load during every hour, its capacity value is not discounted. Flexible load reduces system use periodically, rather than continuously. Because of this, capacity values for flexible load are discounted via an Effective Load Carrying Capacity (ELCC) assignment. The modeling of flexible load on PGE's system currently produces ELCCs between 40% and 80%, which results in a discount of 20%-60% relative to EE.

EE is also credited with transmission and distribution deferral values per PGE's Marginal Cost Study, a benefit PGE does not currently attribute to its flexible load programs. PGE's proposed investments in ADMS and the DRP are a prerequisite for PGE capturing T&D deferral values for flexible load. The value credited to EE is measure-specific and reflects the hourly peak demand factor per the savings/load shape of that measure. The measure is apportioned value according to the peak coincidence of the savings shape. For EE, distribution deferral values are assigned using bulk system peak conditions as a proxy, as distribution values are not yet available. The full T&D deferral value provides a benefit of around 20% of the (undiscounted) value of capacity. Because flexible load programs have not yet been designed or dispatched to respond to distribution-level system conditions, to date PGE has not attributed these programs with T&D deferral values.

The following table compares the most current values available for flexible load cost effectiveness modeling, with the values PGE provides to ETO for energy efficiency cost effectiveness modeling.

[111] EE also distinguishes time-varying savings shapes, or EE that both reduces overall energy consumption and shifts the time of consumption.

Note that for the existing portfolio, values reflect 2016 IRP outputs, for consistency with program pilot filings.

Table 8 – Cost Effectiveness for Flexible Load vs. Energy Efficiency

Modeling Category	Flexible Load		Energy Efficiency	
	Value	***Source***	***Value***	***Source***
Capacity				
Value	$103	2019 IRP. 2020 $	$103	2019 IRP. 2020 $
ELCC	Varies	RECAP modeling	N/A	
Deficiency	NA		2021	2016 IRP Update
Line Loss Factors				
PGE transmission	NA		1.6%	PGE OATT
Distribution, primary, (industrial)	2.85%	Internal Loss Factor, 2015 GRC Line Loss Study	2.85%	Internal Loss Factor, 2015 GRC Line Loss Study
Distribution, secondary, average (commercial and residential)	4.74%	Internal Loss Factor, 2015 GRC Line Loss Study	4.74%	Internal Loss Factor, 2015 GRC Line Loss Study
Distribution, sub transmission	1.45%			Internal Loss Factor, 2015 GRC Line Loss Study
Distribution marginal to average line loss ratio	70%	Applied to applicable distribution line loss. RAP Marginal Line Loss Study 2011	varies	Power Council's marginal loss formula applied to a generic system load shape
BPA line factor	1.90%	Wholesale market purchase: 1 leg of BPA		
Transmission				
Deferral credit	NA		$9.38	Per kW-yr. 2019 GRC. 2019 $
Winter value			100%	
Summer value			0%	
Distribution				
Deferral credit	NA		$24.39	Per kW-yr. 2019 GRC Marginal Cost Study for sub transmission and substation. Shaped 12x24. 2019 $
Winter value			100%	
Summer value			0%	
Energy		Per MWh. Aurora on-peak forecast. Annual, monthly, or hourly		Per MWh. Aurora forecast, on and off-peak, monthly
Risk Reduction Value	NA		$3.00	Per MWh. 2016 IRP; not updated in 2016 IRP Update. Describes forward price exposure. 2016 $
RPS Compliance	NA		$0.00	Per MWh. In the 2016 IRP Update, no incremental cost of PNW wind net of capacity value and energy value
Regional Act Credit	NA		10%	1978 Power Act. Demand side can be 110% of cost of supply side proxy

Other benefits categories unique to EE are the Risk Reduction Value and the Regional Act Credit. The Risk Reduction Value reflects the hedging value of avoiding future price spikes due to reduced energy market purchases. This value is modeled in the IRP process by modeling scenarios with and without EE.

Lastly, the Regional Act Credit provides a 10% "benefits adder" to EE. This adder is in statute per the Power Act[112]. It defines EE as cost effective if it is within 110% of supply side alternatives. This adder was included to preference demand side resources over sources of electric generation, to approximate the value of non-energy and non-monetary benefits.

While DR does not enjoy a "benefits adder", it does privilege demand side resources through the TRC by reducing program costs (rather than increasing program benefits). The following table compares costs included in the RIM test (cost shifting view) and the TRC test (partial societal view) for the December 2018 DR Flex pilot filing. The adjustments result in a 37% decrease in costs under the TRC test:

Table 9 – Comparison of Costs between the RIM and TRC Tests

Cost Categories	Ratepayer Impact Test	Total Resource Cost Test
Administrative	$14.8	$14.8
Capital	$3.1	$3.1
Reduced sales	$0.0	$0.0
Incentives	$26.2	$0.0
Transaction costs	NA	$0.0
Value of Service Lost	NA	$8.3
Total	$44.1	$26.2
Total program cost delta		*($17.9)*

Unlike EE, the four test protocol results in a demand side advantage that varies by program. The larger incentives are as a share of the total program budget, the greater the impact of their exclusion from the TRC test.

Staff recommendation 1: The use in all calculations of the same base values as those employed for EE, specifically found in UM 1893.

The primary differences between the two valuations is the assignment of T&D deferral values, and the greater demand-side premium that flexible load is assigned via the TRC. EE reduces energy consumption and thereby alleviates system constraints. However, even with EE, there is locational and operational uncertainty at the distribution level as to whether the measure actually leads to a capital deferral. The T&D deferral value is applied as a simplification. For EE that reduces but also shapes consumption, EE stakeholders have assigned T&D deferral value in alignment with bulk system conditions, as distribution level conditions – and installation location

[112] Northwest Power Act §3(4)(D), 95 Stat. 2699.

of EE investments – are not yet detailed. The second scenario – energy shaping – is akin to flexible load.

The assignment of values not yet known is a difficult subject that PGE has grappled with internally. Across all program design and grid services, PGE has not assigned values that cannot be verified. For flexible load, we are building programs for a future distribution system that we are not yet able to model. However, we continue to believe that defensible assignment of financial value is crucial. We look forward to bringing stakeholders into this conversation.

4.4 Results

In the planning phase, PGE's pilot proposals all exceeded a TRC Test of 1.0. PGE has invested in flexible load resources with the expectation that they will mature into cost-effective programs. As proposals moved into field testing, however, some TRC results have fallen below 1.0, reflecting the differences between PNW and national results that informed planning values, and the many technological, user education, and other challenges that pilots work through once deployed in the field. PGE is working to improve cost effectiveness through both specific priority actions tailored to each pilot and through portfolio-wide efficiency improvements.

Table 10 – Current Cost Effectiveness Test Results for Flexible Load Initiatives

Initiative	TRC	PAC	RIM	PCT	Date of Estimate	Key Actions to Improve C:E
MF Water Heaters	0.82	0.49	0.49	9.74	May 2020	Increase connectivity, decrease over-rides, decrease costs
Energy Partner	1.23	0.86	0.85	2.04	May 2020	Increase participation
Thermostat	1.06	.64	.62	4.17	March 2020	Reduce costs (vendor, thermostat purchase and installation), increase participation
Peak Time Rebate	0.85	0.56	0.56	4.00	Feb 2020	Increase load impact, improve baselining, decrease costs

PGE has launched several flexible load pilots over the past four years with the goal of delivering carbon-free grid services, while meeting PGE's DR capacity goals[113]. All of PGE's flexible load projects are planned and managed to be cost effective over the life of the project. However, the process of translating planning assumptions into operational programs means that achieving programmatic cost effectiveness is a process of continuous improvement.

Since initiation, PGE has 1) field tested planning assumptions and market acceptance; 2) vetted alternative technological solutions; 3) incorporated vendor expertise into PGE implementation teams; 4) experimented with multiple communication networks; 5) integrated with data and billing systems; and 5) generated process maps to integrate programs into real time operations. Through

[113] See Order 17-386, Docket LC 66 where the Commission set demand response goals of 77MW winter and 69MW summer capacity. These goals were set as a floor.

this process, the Company is building expertise in the flexible load lifecycle that ultimately result in a cost-effective portfolio. PGE's work is an ongoing iterative process.

PGE's current DR activities are not just new applications of flexible load technology for the company but also new in the Northwest[114]. Because of this, PGE launched these activities as demonstrations or pilots. Over the last four years, PGE has ramped efforts quickly to meet MW targets, stood up new organizational functionality, and field-tested a range of program concepts and technologies within PGE's unique market and operational context.

PGE understands and supports the expectation that our investment in DR will mature into a cost-effective resource. Cost-effectiveness is a Commission imperative and is crucial to limiting rate pressure upon our customers. The learnings from the last four years of program growth are incorporated into this proposal's recommendations to reduce program cost and improve performance in an effort to evolve PGE's flexible load program to achieve cost effective resource build[115].

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[114] Even where DR programs have long histories, such as DLC programs in Florida, each climate produces unique results, with unique customer impacts. While some learnings can be translated across geographic regions and climates, demonstrations or pilots are necessary to understand the application of each flexible load technology to the Northwest.

[115] Demand response is not entirely similar to energy efficiency. The Commission recognized the difference in 2015 when the Commission directed PGE to the California's Demand Response Cost Effectiveness Protocols in UM 1708. The Commission then furthered their policy on DR resource builds through Order No. 17-386 in LC 66 PGE's 2016 IRP, which required several actions on DR including building a 77MW DR resource by 2021.
In response, PGE made several changes to program development, supporting infrastructure and the DR resource build processes. These start-up costs are reflected in our activities' current expenses and budgets. PGE built each pilot individually because we did not have the regulatory framework that has been developed for EE through years of trial and error. To assure resource build, PGE used the latitude afforded under the Commission definition of pilot activity - including the exceptions to cost effectiveness found in UM 551 - coupled with close and regular reporting to the Commission and Commission Staff. Many of the investments made through our initiation of the DR resource build will be shared across a portfolio of activity; these start-up investments make the evolution to cost effectiveness easier for the next iteration of activity. PGE has been transparent in our efforts to meet the DR goals set by the Commission.

PGE has identified six lanes within the journey to a cost-effective flexible load portfolio. Some we are driving; others we are tracking and ready for engagement with the changing context in which we work, as seen in Figure 25 and Figure 26, respectively:

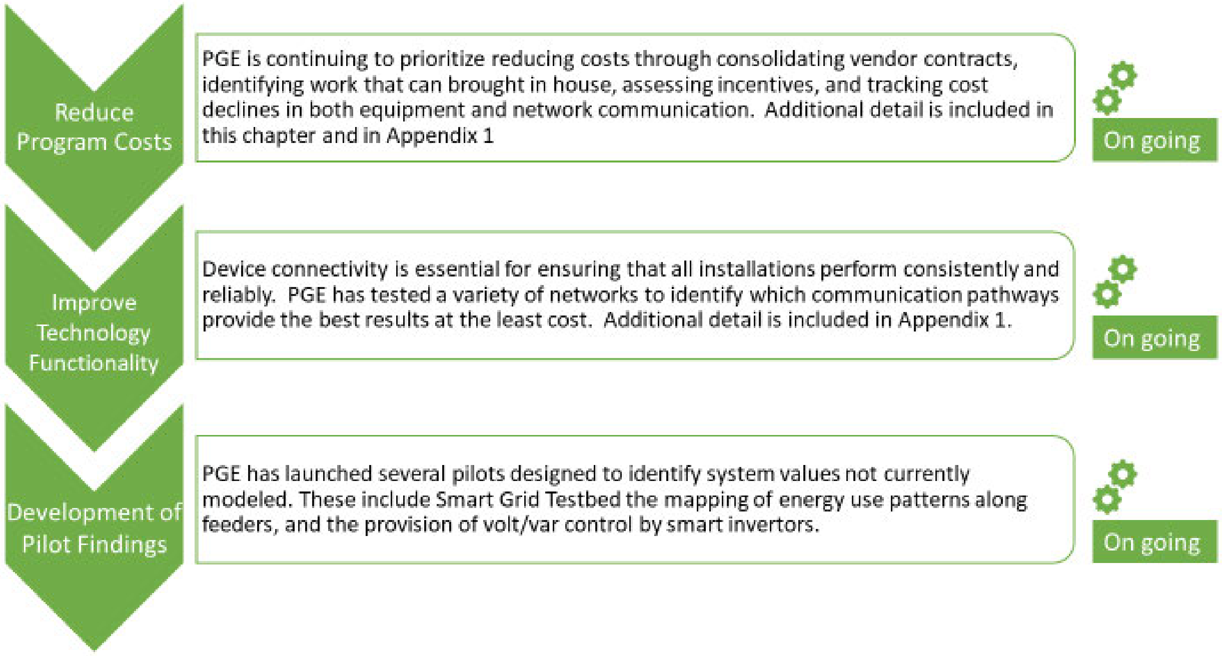

Figure 25 – Current Efforts toward a Cost-Effective Flexible Load Portfolio

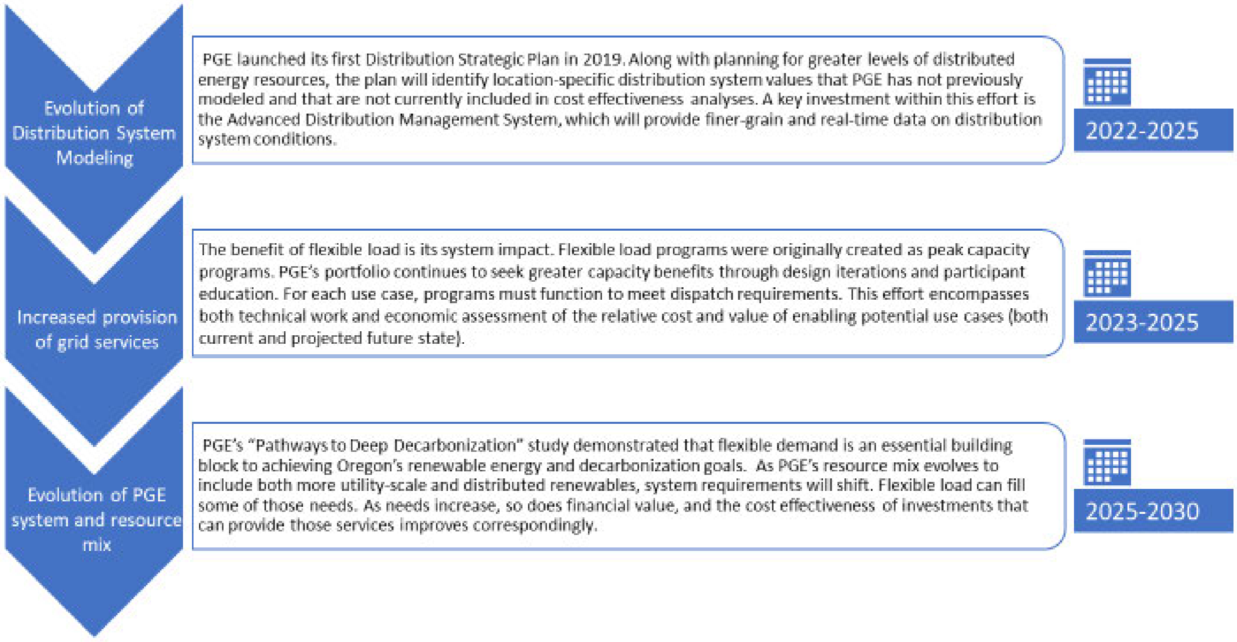

Figure 26 – Anticipated Efforts toward a Cost-Effective Flexible Load Portfolio

4.4.1 Flexible Loads as a Grid Service

Cost effectiveness compares benefits and costs. Expanding the benefits that flexible load provides to grid services beyond capacity can improve benefit cost ratios. This section provides an overview of services that flexible load can provide today or may provide in the future.

The ability of any technology to provide these services reflects many factors, including response time, cycle duration, and ability to integrate within the relevant dispatch entity. This high-level summary of those factors is intended to inform explorations of how flexible load can be optimized in support of PGE's operational needs.

PGE envisions a future in which flexible load resources are co-optimized across the transmission and distribution systems through Virtual Power Plants. As noted above, PGE sees these emerging "shimmy" resources as a key opportunity to maximize the value of flexible load and as a key tool for reliability in a decarbonized future. PGE is still learning about the capabilities, customer impacts, and value of these emerging flexible load opportunities. Even as these demonstrations and pilots progress, PGE recognizes that the core value in DR and flexible load is providing reliable capacity to meet resource adequacy needs. Flexible load has a real, proven ability to replace peaking capacity; even as PGE explores the opportunity for flexible load to provide the grid services described below, PGE recognizes that resource adequacy capacity is the core value of flexible load programs.

PGE also recognizes that the value that flexible load offers to the grid as a whole must be co-optimized on a locational basis. Through the DRP, PGE is exploring both locational value and opportunities to co-optimize across various grid services. PGE recognizes that flexible load offers multiple value streams; PGE is working diligently to assess the ability to stack these products to produce optimized, least cost solutions for our customers.

4.4.1.1 Current Grid Services Program Capabilities

Table 11, illustrates grid services capabilities of PGE's current and planned portfolio.

Table 11 – Grid Service Capabilities of Current and Planned Portfolio

	Resources						
Grid Service	**DLC Daily**	**DLC Seasonal**	**Behavioral DR**	**Res Battery**	**C&I Battery**	**EV**	**PV Smart Inverters**
Distribution Services							
Volt/Var control				Current	Current		
Frequency response				Current	Current	Near-term	
Outage Mitigation and Upgrade Deferral	Near-term	Near-term	Near-term	Near-term	Near-term	Near-term	
Transmission Services							
Congestion and Upgrade Deferral	Near-term	Near-term	Near-term	Near-term	Near-term	Near-term	
Generation Services							
Capacity	Current	Current	Current	Current	Current	Current	
Value of Energy	Current	Near-term	Near-term	Current	Current	Current	
Flexibility services							
Contingency Reserves							
Spinning reserves	Current			Current	Current		
Non-spinning reserves	Current	Near-term		Current	Current		
Load following / Energy Imbalance	Longer-term	Longer-term		Near-term	Current	Near-term	
Regulation				Near-term	Current	Near-term	
Voltage support	Current				Current		Current
Black start	Current			Current	Current		
Participant Benefits							
Power reliability	Current	Current	Current	Current	Current		
Outage mitigation				Current	Current	Longer-term	Current
TOU charge reduction				Current			
Demand charge reduction					Current		

4.4.1.2 Distribution Services

4.4.1.2.1 Autonomous Volt/Var Support

Definition: Autonomous Volt/VAr support is a local, distribution level function in which a DER adjusts VArs to support local voltage within a prescribed band. Advanced VAr management is one tool a utility can use to manage system voltage and power factor[116].

Requirements:

- Response time: within seconds
- Call frequency: continuous
- Duration: minutes to hours. Most events are less than 3 minutes.
- Exclusive assignment: no, can occur concurrently

Dispatch: This service is enabled rather than dispatched. For instance, residential batteries will include Volt/VAr support as a built-in feature that PGE can turn on and off via a central control. PGE will turn this on when appropriate and the device will provide services autonomously. This use case will be more valuable when Advanced Distribution Management System (ADMS) is in place (anticipated in 2022). Post-ADMS this service will be enabled and managed by the Distribution System Operator.

Applicability to flex load: As PGE advances our understanding and capabilities of flexible load we will address the potential value of this service when and if provided by flexible load.

4.4.1.2.2 Autonomous Frequency Response (Freq/Watt)

Definition: The entire WECC system needs to maintain frequency within a certain band both during normal operations and in response to a disturbance or major event. The NERC requires PGE to contribute to maintaining this frequency following a major event. PGE meets this requirement by dispatching energy resources (e.g. sourcing or sinking kW from the system) to help maintain interconnection frequency within the predefined bounds in response to a system frequency deviation.

Requirements:

- Response time: within seconds
- Call frequency: once every few months
- Duration: 15 minutes
- Exclusive assignment: has limited ability to be combined with other opportunities

Dispatch: Scheduled by Grid Operations[117]; dispatched automatically. This use case is enabled rather than dispatched. For energy storage, it is responsive to local monitoring and control functions.

[117] PGE is required to supply sufficient frequency response to comply with NERC Reliability Standard BAL-003-1.1: Frequency Response and Frequency Bias Setting. PGE's Frequency Response Obligation is the amount of frequency response that PGE's Balancing Authority is expected to provide to the interconnection, measured in MW of response per 0.1 hz. PGE's Frequency Response Obligation for 2019 was -16.9 MW / 0.1 hz. In other words, for every 0.1 hz of frequency loss, PGE is required to response with -16.9 MW. A 0.2 hz loss would require PGE to respond with 33.8 MW.

Applicability to flex load: Primary frequency response is typically provided by the governor droop setting on a generator, typically set at 5%. PGE has also successfully experimented with providing frequency response with battery storage at the Salem Smart Energy Center.

Flexible Loads including water heaters and battery storage are capable of providing autonomous frequency response under certain conditions[118].

4.4.1.2.3 Distribution Outage Mitigation and Upgrade Deferral

Definition: This service is the avoidance or deferral of distribution system investment. PGE's management of and investment in its distribution system is driven primarily by reliability targets: PGE plans for N-1 resiliency, meaning all components have some form of redundancy[119]. Flexible load can defer investment in system upgrades specific to each to each system constraint.

Requirements:

- Each application is uniquely tailored to address the specific constraint.
- Exclusive assignment; some feeders will align with PGE's overall system peak.

Dispatch: Primarily dispatched manually by Distribution System Operation solution rather than autonomous; long-term, this function could be automated.

Applicability to flex load: Traditionally, distribution equipment upgrades have been utilized in response to load growth. However, flexible load can be utilized to defer to mitigate this investment. An example of using DER to manage congestion and defer additional distribution investments is National Grid's Island Ready project that installed a 48 MWh battery, upgraded distributed generation, and installed substation automation to defer the need to build a third undersea cable to serve Nantucket Island[120].

4.4.1.2.4 Distribution Congestion and Upgrade Deferral

Definition: Electric power distribution is the final stage in the delivery of electric power; it carries electricity from the transmission system to individual consumers. When load growth exceeds the capability of the distribution equipment to meet the demand for electricity, equipment must be replaced or upgraded. Flexible load can offset the need for distribution system investment with custom solutions targeting the specific constraint.

Requirements:

- Response time: depends on required upgrade
- Call frequency: depends on required upgrade

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[118] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-21152.pdf

[119] An N-1 planning standard ensures that the system can withstand a "primary contingency," or a loss of one or more system elements through a planned or unplanned event and maintain uninterrupted service. PGE currently performs in the top quartile for the primary reliability metrics.

[120] National Grid's IslandReady: A Nantucket Electricity Initiative Factsheet. Available at: https://islandreadynantucket.com/wp-content/uploads/2019/08/IslandReady-Fact-Sheet_August-2019.pdf

- Duration: depends on required upgrade
- Exclusive assignment: No

Dispatch: The dispatch depends on the resource type. Manual by System Control Center via EMS. Long-term, this function could be automated.

Applicability to flex load: Distribution upgrades are traditionally done by replacing/upgrading existing equipment. Flexible loads, including batteries, DR, and EE can defer or mitigate the need for these upgrades in certain circumstances.

4.4.1.3 Transmission Services

4.4.1.3.1 Transmission Congestion and Upgrade Deferral

Definition: Transmission is distinguished from distribution by the operational characteristics of the facility as defined by the FERC's Seven Factor Test. For PGE, voltage above 115 kV is classified as transmission. Similar to distribution system deferrals, flexible load can offset the need for transmission system investment with custom solutions targeting the specific constraint. Transmission system services require larger scale solutions than distribution system services.

Requirements:

- Response time: depends on required upgrade
- Call frequency: depends on required upgrade
- Duration: depends on required upgrade
- Exclusive assignment: No

Dispatch: The dispatch depends on the resource type. Manual by System Control Center via EMS. Long-term, this function could be automated.

Applicability to flex load: Transmission upgrades are traditionally done by constructing new transmission lines or replacing/upgrading existing transmission equipment. Flexible load can defer or mitigate the need for these upgrades in certain circumstances. For example, the New England Independent System Operator has identified more than $400 million in previously planned transmission investments in New Hampshire and Vermont that are now deferred beyond its ten-year planning horizon due to energy efficiency.

4.4.1.3.2 Voltage Support

Definition: Nearly all power system loads require a combination of real power (watts) and reactive power (VArs). Real power is supplied by a generator, but reactive power can be supplied either by a generator or a local VAr supply. Most of the loads connected to the grid distribution system such as motors, transformers and cables are inductive in nature and cause a reactive component of current to flow in the circuit supplying them as well as a resistive current flow feeding the device. The energy to supply this reactive current (whether for inductive or capacitive loads) has to be supplied by the generator which must divert some of its available energy to satisfy this demand. Additionally, because the traditional generators supply a multiplicity of loads, the voltage can vary widely across different areas of the distribution system. Smart inverters and batteries are capable of supplying local VArs where they are needed. This improves local power quality. Additionally, a generator that provides VArs sees a reduction in energy output. PGE values the increased generation efficiency that would result from providing local VArs.

Requirements:
- Response time: autonomously responsive to local voltage needs
- Call frequency: continuous
- Duration: continuous, when providing the service
- Exclusive assignment: no

Applicability to flex load: Today, reactive power is supplied by generators and capacitor banks that adjust the phase shift or phase angle between the voltage and the current. Smart inverters and batteries are able to supply reactive power.

4.4.1.3.3 Black Start

Definition: Black start is the process of restoring an electric power station or a part of an electric grid to operation without relying on the external electric power transmission network to recover from a total or partial shutdown. PGE is required by NERC to maintain a restoration plan that enables PGE to recover from a variety of outage scenarios. Batteries are particularly well suited to assist with black start restoration. Additionally, DR can alleviate some of the challenges with system restoration caused by cold load pickup by phasing in load in a more controlled manner[121].

Requirements:
- Response time: N/A.
- Call frequency: called during outages
- Duration: application dependent
- Exclusive assignment: no

Applicability to flex load: Black Start is provided by generators specifically configured to restore areas of the electrical grid in a specific sequence. Batteries could be utilized to provide the initial start-up energy to initiate a Black Start sequence. Additionally, DR could be deployed to mitigate cold load pickup and facilitate system restoration.

4.4.1.4 Generation Services

4.4.1.4.1 Generation Capacity

Definition: Capacity represents the ability of a resource to contribute to meeting a resource adequacy target. For example, PGE plans to a Loss of Load Expectation (LOLE) of 1 day in 10

[121] Cold load pickup is the well-known problem defined as excessive inrush current drawn by loads when the distribution circuits are re-energized after extended outages. During extreme weather conditions, these currents can be high enough to appear as faults and/or overload, resulting in blown fuses or breaker re-trips, further extending the outage duration.

years. The capacity contribution of a resource, such as a flexible load program, is the amount of MW of a conventional proxy capacity resource that can be avoided. Generation capacity value represents the potential to avoid costs associated with new resources. The capacity value of the resource is calculated as the net cost of new entry (net CONE) for a new proxy capacity resource multiplied by the resource capacity contribution. PGE performs this analysis within the IRP.

The term capacity most frequently appears in a long term planning context as is associated with Resource Adequacy. Resource adequacy is deliberately planning one to four years ahead to ensure there are enough resources – generation, efficiency measures, and DR including flexible load – to serve loads across a wide range of conditions with a sufficient degree of reliability At dispatch, PGE's ability to serve its load is measured by resource sufficiency: does PGE have sufficient energy, flexibility, and reserves to meet its load service and reliability obligations?

Requirements:

- Response time: Either day ahead or hour ahead.
- Call frequency: No threshold, but response time may affect capacity contribution.
- Duration:1-6 hours.
- Exclusive assignment: No. A resource can provide capacity while providing other services.

Dispatch: Scheduled and dispatched by PGE Power Operations either day-ahead or hour ahead to meet forecast load.

Applicability to flex load: Capacity is traditionally provided by dispatchable generation, energy efficiency, and flexible load. Most existing flexible load programs provide capacity; all of PGE's current flexible load pilots provide capacity.

4.4.1.4.2 Value of Energy

Definition: Value of Energy is the ability to shift some of the required energy from higher priced periods to lower price periods. In Docket No 1751, the Commission defined this service as "[t]rading in the wholesale market by buying energy during low-price periods and selling it during high price periods."

PGE forecasts energy value for resources over the long term within the IRP based on the ability of the resource to avoid or better optimize wholesale market purchases. In the near term, this use case is realized as a reduction in power costs.

Requirements: Not prescriptive, but energy value will depend on how the resource dispatches under different market conditions.

Dispatch: Scheduled by Power Operations according to forecasted energy price. The schedule can be modified to respond to reliability needs.

Applicability to flex load: PGE's Power Operations group optimizes PGE's generation portfolio and makes purchases and sales in the bilateral market to capture this value. Flexible load that shifts energy out of high-priced periods and into lower priced periods can capture this value.

4.4.1.5 Flexibility Services

As flexible load pilots mature into programs, PGE is working with power operations and the balancing authority to incorporate flexible load programs and the grid services they are capable of providing into PGE's daily operations.

In order to balance generation and load on a second-to-second basis and to respond to unexpected conditions, PGE is required to carry a certain amount of online capacity that is able to respond to these moment-to-moment fluctuations and contingency events at all times. Operationally, this flexibility is broken into "operating" reserves and "contingency" reserves. Operating reserves are used to account for the *expected* moment-to-moment variations between supply and demand, and to account for forecast error. Additionally, PGE carries contingency reserves to ensure that PGE is able to recover from *unexpected* events. PGE must carry sufficient reserves to consistently meet North American Energy Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC) reliability standards.

While each grid service has its own performance criteria and operational obligation, from a real-time perspective, PGE also co-optimizes these services across PGE's portfolio. If a resource is held "in reserve" to provide a flexibility service, then it is not available to generate the energy needed to serve load. The difference between the market price and the resource's incremental cost to generate is considered an "opportunity cost." For example, if the market price is $30, and a resource's cost to generate is $25, the lost opportunity cost is $5. PGE power operations continually re-optimizes PGE's resources on a week-ahead, day-ahead, and real-time basis in order to reliably serve load at the least cost.

Co-optimization in long-term planning is done differently than co-optimization for real-time operations. For long term planning purposes in the IRP, PGE groups multiple services related to system flexibility into a broad category of "flexibility services." These include load following, regulation, and contingency reserves. These services are grouped together within the IRP because the evaluation of their value to the system occurs on a portfolio basis and requires co-optimization in a manner that accounts for the interactions between each service. In IRP modeling, regulation and load following have both an energy and a capacity component; however, from an operational perspective, the capacity associated with these services is billed under regulation[122] while the energy is billed under energy imbalance.[123] Additionally, PGE considers the value associated with operating the system more efficiently due to the ability to provide a portfolio of flexibility reserves as part of the Flexibility Value quantified within the IRP.

While PGE plans for and co-optimizes these services together from a planning perspective, within each operating hour, PGE is required to carry each service separately in order to meet NERC and WECC reliability obligations. Each service has specific operational and performance criteria. Therefore, while there is a co-optimization opportunity when considering PGE's flexibility reserve

[122] OATT Schedule 3: Regulation and Frequency Response Service

[123] OATT Schedule 4: Energy Imbalance Service and OATT Schedule 4a: Retail Energy Imbalance Service

portfolio holistically, PGE must be able to provide each service independently in real time operations.

Finally, it is important to differentiate between the definition of flexible load used within this document and the definition of the flexibility or flexible service used by the IRP and power operations. Flexible load is a categorization of behind the meter, grid-enabled, customer-sited activities. These activities can vary from customer behavioral changes to advanced, autonomous grid-connected devices that provide any of the services described in this section. The definition of flexible load in this document aligns with national discussions of services that are provided from the behind the meter resources found on the distribution system.

This does not mean that the programs group is defining a new type of service called flexible load. The definitions of grid services beyond energy and capacity are defined by NERC, WECC and FERC to ensure regional consistency and cost allocation. PGE's flexible load programs will need to provide services that meet existing definitions and requirements in accordance with PGE's load service and reliability obligations.

4.4.1.5.1 Contingency Reserves

Definition: Contingency reserves refers to both spinning and non-spinning reserves. NERC requires that each Balancing Authority provide resources on a stand-by basis to respond to unplanned events. PGE is required to carry reserves to cover three percent of system load plus three percent of online generation. Reserves are distinguished between spinning reserves (synchronized to the grid) and non-spinning reserves (not synchronized to the grid). Load is always considered synchronized to the grid and is therefore considered a spinning reserve.

Requirements:

- Response time: within 10 minutes
- Call frequency: Up to a few times per month
- Duration: minimum of 60 minutes
- Exclusive assignment: The ability of a resource to provide contingency reserves will depend on the extent to which the resource is also scheduled to provide other services, including energy, load following, and regulation.

Dispatch: PGE's Balancing Authority Operators dispatch operating reserves in response to unplanned events. Currently, Distributed Standby Generation (non-spinning reserves) is dispatched via GenOnSys, PGE's Distributed Energy Resource Management System (DERMS). Spinning reserves are provided by PGE's online generating resources.

Applicability to flex load: PGE meets half of its reserve requirement with Distributed Standby Generation, which provides non-spinning reserves. The remaining requirement is met through the available capacity of online generation[124]. Flexible loads that are online and capable of responding

[124] For a generator to supply spinning reserves, it must be online, with additional upward dispatch capability, limited by the generator's 10-minute ramp rate. For example, consider a generation plant

within 10 minutes are able to provide spinning reserves. Demand Response, electric vehicles, and storage can all provide spinning reserves. DR from interruptible loads participates in ancillary service markets for contingency reserves in several different markets, including ERCOT, MISO, PJM, and NYISO. Usually, these programs call on interruptible loads solely under contingency events (though NYISO co-optimizes contingency reserves into energy markets under certain conditions) and based on a low frequency threshold or system operator command[125]. Because PGE already meets 100% of its non-spinning obligation with the Distributed Standby Generation program, PGE has no current need for additional non-spinning reserves.

4.4.1.5.2 Regulation and Load Following Reserves[126]

Definition: Regulation is the online capacity necessary to maintain the balance between generation, load, and exports, in real time. Regulating reserves are governed by NERC regional reliability standard BAL-001-2. Regulation Up describes an increase in energy production or decrease in consumption; Regulation Down describes a decrease in production or increase in consumption. PGE meets this obligation by reserving capacity on specific units to respond to upward or downward fluctuations within each operating hour. Currently, PGE bids regulation capacity into the Energy Imbalance Market[127].

Requirements:

- Response time: four seconds
- Call frequency: continuous while in regulation mode
- Duration: seconds to minutes

was online and generating at 100 MW, but had a nameplate capacity of 200 MW. If the generator's ramp rate is 1 MW/minute, the generator could supply 10 MW of spinning reserves. If the generator's ramp rate is 5 MW/minute, the generator could supply 50 MW. Because of the ramp rate requirements, PGE typically carries spinning reserves on its most flexible generation, especially hydro and gas generation.

[125] https://pdfs.semanticscholar.org/f0fc/f6962bf9eb10e34ef0939c59274997899809.pdf

[126] PGE models Regulation and Load Following with both an energy and a capacity component; however, under the PGE OATT, the capacity associated with these services is billed under regulation while the energy is billed under energy imbalance. While PGE models regulation (a fast product, needed to address fluctuations under 5 minutes) and load following (a slower product, needed to address fluctuations greater than 5 minutes) separately, the PGE OATT uses the single term "regulation" to mean all capacity needed to meet intra-hour variation. Post FERC Order 764: Integrating Variable Energy Resources, regulating reserve rates typically include "fast" "slow" and "replacement" regulating reserves that are generally analogous to PGE's differentiation between regulation and load following.

[127] The Energy Imbalance Market requires PGE to meet a series of Resource Sufficiency Tests, including a flexible ramping test that ensures each balancing authority area has sufficient ramp capability to meet it fifteen-minute forecasted energy and flexible ramping product requirement. PGE uses regulation capacity to meet PGE's obligations in this test. PGE uses the "available balancing capacity" tool to ensure sufficient regulation capacity is available to meet PGE's internal balancing authority needs. When needed, PGE's balancing authority operators will also dispatch generators that are providing regulation outside of the EIM market dispatch instructions based on system conditions.

- Exclusive assignment: The ability of a resource to provide regulation will depend on the extent to which the resource is also scheduled to provide other services, including energy and contingency reserves.

Dispatch: Automated Generation Control Center (via PGE's Energy Management System)

Applicability to flex load: Historically, regulation has been provided by online generation capable of responding quickly and accurately to an automated signal from PGE's Energy Management System. Hydroelectric generation and natural gas generation provide the majority of regulation reserves in the Northwest. Flexible load resources, including batteries, EVs and DR are capable of providing regulation.

4.4.1.5.3 Energy Imbalance

Definition: Energy Imbalance refers to the ability to respond to fluctuations in loads and generation to mitigate imbalances between scheduled energy, delivered energy, and load. PGE manages imbalance on this time scale through participation in the Energy Imbalance Market.

Requirements:

- Response time: 5 minutes ("fast" resources) or 15 minutes.
- Call frequency: Called via market signal; call is responsive to bid price and market conditions
- Duration: Award is based on a 5-minute or 15-minute interval
- Exclusive assignment: The ability of a resource to provide energy imbalance will depend on the extent to which the resource is also scheduled to provide other services, including energy, contingency reserves, and regulation.

Dispatch: Energy Imbalance is dispatched through the California Independent System Operator Energy Imbalance Market. Resources participating in this market must meet EIM qualifications.

Applicability to flex load: Today, the majority of PGE's generating resources, including VERs, are bid into the Energy Imbalance Market as "participating resources"[128]. While all flexible load resources are eligible to participate in the Energy Imbalance Market, this participation must weigh the costs of participation, such as communications and metering requirements, against the projected market revenues.

4.4.1.6 Participant Benefits

4.4.1.7 Outage Mitigation

Definition: Providing reliable, safe, clean, and affordable power is at the core of PGE's customer proposition. Flexible loads are an emerging tool to enhance the value to the customer across these metrics. Flexible loads can be a part of supporting outage mitigation for a customer or in a

[128] Qualified Facilities (QFs), Colstrip and Westside Hydro are currently non-participating resources due contractual or regulatory restrictions.

microgrid. If an energy resource or battery provides backup power, load modifiers can extend the duration of that power. Flexible load can effectively support customer loads when there is a total loss of power from the source utility. This support requires the flexible load system to island during a utility outage and resynchronize with the utility when power is restored. The energy capacity of the flexible load system relative to the size of the load it is protecting determines the time duration that the storage can serve that load[129].

Dispatch: Establishment of customer or microgrid islanding is an automatic service. Ensuing load adjustments can be automated or manual.

4.4.1.8 TOU Charge Reduction

Definition: Time-of-use is a rate plan in which rates vary according to the time of day, season, and day type (weekday or weekend/holiday). Higher rates are charged during the peak demand hours and lower rates during off-peak demand hours. This rate structure provides price signals to energy users to shift energy use from peak hours to off-peak hours and encourages the most efficient use of the system.

Time-of-use pricing incorporates the expected variability in wholesale energy prices into retail rates, offering customers a lower rate during periods where overall demand, and therefore price, is lower.

Time-of-use rates can be coupled with technology to automate customer response to the price signal.

Dispatch: None; Technology-enabled Time-of-Use can be dispatched on a day-ahead or hour-ahead basis.

4.4.1.9 Demand Charge Reduction

Definition: Demand charges reflect the peak power demand (kW) of the customer each month, as opposed to the amount of energy (kWh) used over the course of the month. Flexible load can be used to manage a customer's peak usage, thereby lowering the customer's demand charge. Demand charges apply to some commercial and industrial customers.

Dispatch: The customer would dispatch the flexible load to manage their own peak demand. The customer could perform this dispatch automatically, through their building energy management system, or manually.

[129] Akhil, A.A., G. Huff, A.B. Currier, B.C. Kaun, D. M. Rastler, S.B. Chen, A.L. Cotter, D.T. Bradshaw, and W. D. Gauntlett. 2013. DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA. SAND2015-1002. Albuquerque: Sandia National Laboratories. http://www.sandia.gov/ess/publications/SAND2013-5131.pdf.

Chapter 5 Regulatory Alignment

Chapter Summary

Chapter 5 is not a request for action from the Commission, but is rather provided for informational purposes, and to share with the Commission and stakeholders that PGE looks forward to a discussion about regulatory alignment regarding the investment in flexible load.

Discussion

As prior chapters demonstrate, PGE views Flexible Load Resources as having a significant and growing role in our strategic vision to partner with customers in order to deliver a clean energy future for all. Therefore, PGE is committed to fully embrace and expedite the incorporation of Flexible Load resources into our portfolio.

Historically and across the industry, Flexible Load has not been incorporated into core utility operations, to the detriment of efficiency, customer experience and potential carbon reductions. This is because the traditional utility model lacks financial incentives for utilities to pursue Flexible Load Resources at scale. For PGE, this issue has not deterred our efforts towards meeting established 2016 IRP goals. However, we would be remiss is we did not recognize the need to align incentives as programs mature.

The American Council for an Energy-Efficient Economy (ACEEE) posits a solution to the business model barriers that utilities face when evaluating Flexible Load Resources at scale, writing, "To make SDR [Strategic Demand Reduction] a core part of the utility business model, incentives and other policies can continue to strengthen the link between utility performance on SDR and investor returns."[130] PGE raises this as a potential area for regulatory model evolution.

The current economic climate requires sensitivity in prioritization. In light of this, PGE is not seeking an earnings mechanism at this time. However, we are ready, when the Commission signals, to open a discussion on regulatory earnings mechanisms for Flexible Load.

Several states have sought to better align utility incentives by introducing new regulatory mechanisms for flexible load. Regulatory mechanisms introduced across the country vary from simple – for example, applications of the cost-plus model to flexible load expenditures – to more complex, value-based approaches. States such as Hawaii and Michigan have approached the issue cautiously by introducing a single new regulatory mechanism initially, while other states simultaneously introduced a suite of new regulatory mechanisms that vary in structure and magnitude. For example, New York's Reforming the Energy Vision ("REV") created four types of new regulatory mechanisms. The simplest and most widely adopted was cost-plus, regulatory asset treatment for energy efficiency program spend. Performance Incentive Mechanisms (PIMs)

[130] ACEEE report https://www.aceee.org/research-report/u2003 page 7

in the form of Earnings Adjustment Mechanisms, both programmatic and outcome-based, were also introduced as well as Non-Wires Solutions incentives based on administratively calculated shared benefits. Lastly, policy enabling Platform Service Revenues was introduced but has had limited adoption by New York utilities to date.

Evaluating the various forms of regulatory incentive mechanisms for flexible load is outside the scope of this filing, however, PGE offers the following design principles[131] to help the Commission streamline an investigation into the topic, should it be pursued:

1. Evaluate investment ***based on established need***, in alignment with IRP practices.

2. Keep incentive structures as ***simple and transparent*** as possible.

3. Aim to achieve ***investor indifference*** between the quality of earnings opportunities associated with traditional rate base and new regulatory mechanisms for flexible load, including balanced reward for increased regulatory and/or execution risk.

4. Commit to multiyear programs that ensure ***durable policy signals*** that allow utilities to plan and invest over long-time horizons.

5. Enable an ***adaptive process*** that promotes continuous improvement and allows regulators and stakeholders the opportunity to iterate and expand the complexity and diversity of regulatory incentive mechanisms.[132]

We offer this introductory discussion of new regulatory mechanisms for flexible load resources in response to perceived interest in the topic by the Commission and stakeholders. It is PGE's view that evolving the regulatory framework to align incentives for utilities to embrace flexible load resources is in customers' interest and is in line with the clean energy vision articulated by the Governor and the OPUC. PGE would welcome the opportunity to explore the topic more in-depth with the OPUC and stakeholders, within the broader context of how the regulatory framework should evolve to best serve customers.

[131] Following these principles may result in vintages of regulatory incentive mechanisms that evolve over time to allow for incorporation of learnings while not violating retroactive ratemaking.
[132] https://rmi.org/wp-content/uploads/2018/10/RMI_Navigating_Utility_Business_Model_Reform_2018-1.pdf
https://info.aee.net/hubfs/AEE%20Institute_Utility%20Earnings%20FINAL_Rpt_1.30.18.pdf
https://www.aceee.org/research-report/u2003

Appendix A

A.1 Portfolio View and Summary

Existing Demand Response Pilots:

PGE Opportunities

- The cost to acquire MW is trending downwards as programs independently achieve economies of scale, negotiate cost reductions, as well as continually approve operational efficiencies. As the pilots evolve, the team is increasing focus on a portfolio management approach to identify opportunities for further reductions. This includes a review of internal resources dedicated to pilots, third party services, centralized IT infrastructure, and process synergies.
- As the pilots evolve to deliver more reliable results and are integrated as deployable resources into Power Operations, PGE will be able to drive maximum benefit: ensuring direct alignment of dispatch with price, performance and grid stability needs. Overall, PGE DR portfolio will be leveraged to reduce pressure on electricity rates.

Regulatory Opportunities

- Flexibility to adjust existing pilots:
  - Each pilot has a budget, procedures, and reporting requirements that have been developed uniquely in support of PGE's 2016 IRP goal and filed with the OPUC independently. This created arbitrary siloes in how PGE must manage development costs, 3rd party costs (and contracts), operating costs, and evaluation costs. This also bears out in the customer experience as each separate pilot may have very different eligibility and participation requirements.
  - In the future, PGE could create better cost efficiencies if there was portfolio level flexibility to share funding, development costs, and be more agile to respond to dynamic market changes. These areas include
    - Shared development costs
    - DRMS provider consolidation
    - Shared customer outreach and recruitment
    - Asset management consistency
    - Evaluation
- Flexibility to grow the overall portfolio:
  - By managing the demand response product development and pilot deployment at the portfolio level, PGE would have greater flexibility to leverage investments and shift resources to maximize the greatest benefits for the customer and grid reliability.

Table 12 – Flexible Load Portfolio Budgets (Actual $000's)

Demand Response						
Project	Current Status	**2017 and prior** Actuals	**2018** Actuals	**2019** Actuals	**2020** Actuals plus Forecast	**2021** Forecast
Residential DR						
- Flex	Pilot	$ 1,405,259	$ 398,756	$ 2,052,173	$ 2,106,841	$ 3,674,000
- DLCT	Pilot	$ 752,962	$ 1,109,041	$ 3,643,917	$ 1,993,738	$ 3,860,961
- MFWH	Pilot	$ 60,583	$ 1,073,623	$ 2,999,211	$ 1,904,967	$ 4,149,283
Sub-Total Residential DR		*$ 2,218,804*	*$ 2,581,420*	*$ 8,695,301*	*$6,005,546*	*$ 11,684,244*
Non-Residential DR						
- Energy Partner	Pilot approaching Program	$ 4,374,045	$ 2,722,772	$ 2,660,926	$ 4,049,570	$ 3,720,000
Sub-Total Demand Response		*$ 6,592,849*	*$ 5,304,192*	*$ 11,356,227*	*$ 10,055,116*	*$ 15,404,244*
Testbed DR				**Nov '18 - Oct '19** Actuals	**Nov '19 - Oct '20** Actuals plus Forecast	**Nov '20 - Oct '21** Forecast
- Testbed	Project with Demonstrations			$ 265,120	$ 1,721,163	$ 3,779,938
Demand Response Portfolio Total		$ 6,592,849	$ 5,304,192	$ 11,621,347	$ 11,776,279	$ 19,184,182
Transportation Electrification		**2017 and prior** Actuals	**2018** Actuals	**2019** Actuals	**2020** Actuals plus Forecast	**2021** Forecast
- Residential EV Charging	Pilot	N/A	N/A	N/A	N/A	$ 1,559,000
Energy Storage Pilot						
- Residential Energy Storage	Pilot	N/A	N/A	N/A	$ 66,204	$ 761,563

Savings Reporting

- Load impact forecasts reflect both current results and our current best projection for how those results will improve in the future. Much of the measure work PGE is conducting is new to the utility and the region. This means we are developing best known measure savings for our demand response efforts. We also see how measure savings can increase by addressing measure performance and are pursuing those changes. This plays out differently for each of our programs. For Multifamily Water Heater, initial low load impact results are improving due to new technology selection delivering improved device connectivity. For Flex 2.0, the winter 2019-2020 evaluation has just been released, and the program has adjusted its baselining methodology in response to summer 2019 events. These trajectories are expressed as a range of MW savings. The range is a reflection of the process of adjusting planning savings assumptions based on evaluated savings. In contrast, Energy Partner is more mature and by nature more stable. That program is reported as a single MW savings target.

- Two significant market conditions have impacted our portfolio in the first half of 2020, COVID-19 outbreak impacts on our customers and Google Nest's recent decision to not provide demand response management services in support of the Nest Thermostat. In response to COVID in March, PGE made the decision to pause marketing of PTR and Thermostat programs out of sensitivity to customers. That pause lasted approximately three months, and marketing activities have begun again though delivery has been adjusted for safety purposes (for example, technology-enabled virtual thermostat installation assistance). Additionally, we have undertaken significant customer outreach efforts to minimize losses from the Google decision. For the Energy Partner program, we have seen reductions in customer participation commensurate with customers' business operations contracting or closing altogether. At present PGE estimates these market conditions have slowed acquisition to meet our 2019 IRP demand response by about 6 months, though there is uncertainty in that timing due to unknowns related to economic recovery from COVID.

Table 13 – Flexible Load Portfolio MW Savings

Cumulative MW by Program	2017 and prior Results	2018 Results	2019 Results	2020 Forecast		2021 Forecast	
	Average	ummer & Winter		Summer	Winter	Summer	Winter
Residential- Flex	1.5	1.5	6.9	14.7	11.0	18.0	12.0
Residential- Thermostats	4.0	7.3	13.7	24.1	7.0	32.4	10.5
Commercial- Energy Partner	3.0	15.2	21.8	20.2	14.9	26.5	22.3
Commercial- MFWH	0.0	0.9	3.4	3.9	5.9	5.0	7.5
	8.6	24.9	45.8	62.9	38.8	81.9	52.3

A.2 Program Detail

A.3 Multifamily Water Heater Pilot

Total Costs	Megawatts Procured	Cost Effectiveness Score	Next Evaluation
$4.1M (EOY 2019)	3.4 MW	0.82	Summer 2020-21 (due in March 2022)

A.3.1 Program Description

The Multifamily Water Heater pilot aims to enable and operate electric water heaters for demand flexibility. This program provides capacity as well as intra-hour energy and lays the foundation for PGE's DR programs to offer intra-hour grid services to support reliability and renewables integration. The approach is relatively novel as it capitalizes on the density of electric water heaters found in multifamily dwellings. Density is necessary for several reasons. First, broadly distributed assets are more expensive per unit installation thus concentrations of units enable water heaters for a fraction of enabling the same number of units across a broader area. Second, because many multifamily units install the water heater within the living space electric resistance water heaters are used. This niche allows PGE to test advanced use cases from water heaters without affecting Energy Trust and the Northwest Energy Efficiency Alliance's efforts to promote adoption of more efficient heat pump water heaters. Third, having a concentration of these units granted PGE an opportunity to begin working with water heaters as a flexible resource sooner than if we had to wait for higher adoption and concentration rates in the field. Our learnings from this pilot will help inform our approach to single family water heaters. To be clear, PGE supports Energy Trust and the NEEA's effort to increase adoption of heat pump water heaters. However, given the importance of water heaters as a cost-effective approach to supplying flexible services, PGE developed the Multifamily Water Heater Program to learn about developing a flexible load resource from a highly dynamic, ubiquitous appliance.

In addition, PGE is operating the MFWH pilot to evaluate the various modes of device connectivity and different Operating Equipment Manufacturer (OEM) solutions as a means to optimize cost effective program implementation and event performance. Throughout the pilot period PGE will evaluate two approaches to connectivity -- Local Area Network or Wi-Fi communication. This can be done several ways, all of which rely on the presence of a local area network.

The MFWH pilot is structured in phases *designed to move it from* pilot to cost effective program. The first 8,000 installed units took 22 months to install (May 2018-Feb 2020) and will be capable of shifting up to 4MW of energy. We expect to add 2,000 installs in 2020 and 2,500 in 2021, which will create up to 5.0 MW and 7.5MW of shifted energy for summer and winter 2021, respectively.

Table 14 – Multifamily Water Heater Pilot Stages

Timeline	Units installed	Total Capacity
February 2020	8,000 (Program total)	Roughly 4MW (Covid-19 has delayed installations)
EOY 2020	2,000 (Incremental)	3.9MW Summer, 5.9MW Winter
EOY 2021	2,500	5.0MW Summer, 7.5MW Winter
Total	**12,500 retrofit switched units**	**5.0MW Summer, 7.5MW Winter**

PGE expects the per unit install cost for water heaters to continue declining as we install more cell-enabled switches, add mesh or field area networks switches, and add more smart water heaters through the new construction channel. The on-going maintenance costs will also continue to decline as we discontinue installing Wi-Fi switches, which are expensive to maintain connectivity. Conversely, cell-enabled, mesh or field area networks, and smart water heaters cost pennies to maintain connectivity. The project serves as a backbone to provide water heater solutions in new and existing construction markets for single family housing, as well as in owner-occupied MFR housing as early as Q3/2020.

A.3.2 *Multifamily Water Heaters as part of PGE's Decarbonization Strategy*

Water heaters serve every customer in PGE's service territory. Though a large percentage of this market heats their water with end use natural gas, PGE anticipates that as the State pursues carbon reduction strategies the percentage of electrically heated water heaters will grow. Unlike home batteries, roof top storage and electric vehicles, home water heaters are considered a necessary home appliance. Additionally, the cost of electric water heaters is considerably less than the aforementioned. Water heaters are able to shift energy usage, storage energy, and respond to intra-hour event calls without customer hot water service interruptions. This makes the water heater a prime, strategic flexible load resource to help develop a grid flexible enough to integrate variable energy resources while controlling integration costs.

Water heater DR is a critical component to PGE's portfolio because it uniquely represents flexible load. Within the multifamily market, it is estimated that nearly 90% of water heaters are electrically heated and represent 50% of the residential market. Additionally, this type of firm resource can be dispatched daily without affecting customer comfort or disrupting behavior. The fact that within the multifamily market 90% of water heaters are electrically heated, makes this market an excellent space fora flexible water heater program. Multifamily sites allow us to install DR capabilities to several units swiftly, minimizing costs associated with outreach and the costs of establishing service at disparate sites. Additionally, having several units within a single multifamily site allows us to see how the water heaters operate in concert to address capacity and delivery constraints. Moreover, the geographic aggregation of the water heaters creates natural communication and dispatch cost savings. The lessons learned around device installation, device performance and communication will inform development of a single-family water heater program.

A.3.3 *Primary Goals*

The goals for PGE's Multifamily Water Heaters pilot are as follows:

- Successfully operationalize and field deploy retrofit devices that allow for successfully controlling existing water heaters in PGE's DR platform. Operationalize and field deploy
- DR-enabled new water heaters that can be controlled via PGE's DR platform.
- Operationalize communications technology that provides uptime of 90+% for the PGE water heater fleet.
- Reduce costs for hardware, installation, maintenance, and operations down to cost-effective levels while scaling up the program during the pilot period.
- Test, modify, and proof business model with MFR property owners and their agents (MFR property managers).
- Successful dispatch of PGE water heater fleet in DR events with an average capacity of .5KW per water heater during the DR event period.
- Expansion of operation of PGE water heater fleet from DR to daily load shifting. Demonstration of load following capability.

Market potential (opportunity):

- This project targets the large scale / non-owner occupied MFR market: 50 units/site.
- The total number of eligible apartments in large scale MFR housing is 100,000 units. The achievable potential is **50,000 units** corresponding to **25 MW by 2027**.

A.3.3.1 Switch costs

PGE's original start-up budgeted costs per switch installed was roughly $545. Through the pilot we have explored different switch types and vendors. We have improved the effectiveness of our installations. Our third-party contractor negotiated better installation terms thereby lowering overall program costs. Installation work includes not only the switch mounting to the water heater but the communications infrastructure. We have been able to bring down the cost of the communication equipment placement and connectivity resolutions as we learn more about how the water heaters and switch devices operate in the field. We have been successful in bringing down the per unit installation costs to $330. This is a 35% cost savings per switch installed.

A.3.3.2 Communications

There are currently two switch communication methods being explored. Just over 4,400 wi-fi enabled switches with another 3,700 cell-enabled switches. We expect overall installation costs to decrease (due to less equipment needing to be installed – no routers or repeaters) and connectivity to increase (cell-enabled connectivity doesn't have nearly the outages as wi-fi does). We are also looking to explore a second cell-enabled vendor as well as mesh network and field area network options. Cost, latency, telemetry data, installation process lessons (router, repeaters) all play a role in choosing the right vendors.

A.3.3.3 Algorithms

There have been numerous issues with the data from the first winter season. Due to the second switch vendor supply issues, splitting the assets into two groups for control, and the wi-fi connectivity issues we had a very small, callable set per event to analyze. This created a lot of noise within the AMI data as well as inconsistencies between the AMI data, our data management system and our third-party data platform. Being able to increase our fleet will greatly improve our ability to decipher the data between AMI and telemetry. We are also exploring ways to create control sets outside the current fleet to increase the number of available callable switches.

A.3.3.4 Customer/Participation comfort

Our customer participation has been excellent. With almost 8,000 switches installed to date we have less than a 1% opt-out rate (4 customers in total have opted-out of this program). As for customer comfort, we have had less than 15 out of 3500 participating customers over 58 total events experience cold water calls. Of those 15 calls, not all have been directly attributed to the switch. There are four categories the calls have fallen into:

- 5-unknown issues (further tests being conducted)
- 4-faulty switches (repairman went out and removed old switch and installed a new one, problem did not continue)

- 3-installation issue (terminal connection lost, ground wire fell out, etc.)
- 3-water heater issue (dip-tube replaced, heating element not stable, etc.)

In the future we are looking to add maintenance monitoring to try and help detect water heater issues before they become a bigger problem. The monitoring is expected to help detect a burnt-out heater element or a leaking unit. This is a feature that the Maintenance Mangers are eager for us to deliver.

A.3.3.5 Availability of resources

This program has very few limitations on calling events: not for longer than 8-hours and not on weekends or holidays. Nor are we required to notify customers of the scheduled event. We can call events 5-days a week and multiple times a day.

For the winter 2018-19 season we called a total of 58 events from Dec 12th, 2018 through March 1, 2019. Some of those were as short as 2 hours and some as long as 5 hours. Most days we called two events (6-9 A.M. and 4-9 P.M.)

For the summer 2019 season we called a total of 68 events from June 3rd to Sept 30th, 2019. All of those were 4 hour events from 4 P.M. to 8 P.M.

For the Winter 2019-20 season we called a total of 179 events from Dec 2nd, 2019 through Feb 27th, 2020. All events were 3 hours each and called twice a day, from 6-9 A.M. and 5-9 P.M.

These calling structures have allowed us to use the resource for more than peak load reduction capacity. This program is explicitly testing an early evolution of flexible load. Given the poor connectivity rate of the wi-fi switches we are very pleased to see the increase in connectivity with the cell-enabled switches. We are working with our third-party DERMS vendor to continue to get a better report on the uncontrolled units per event.

A.3.3.6 Building configurations

PGE has found that different building types have different mesh network challenges. PGE working to address this challenge. Another obstacle is building configuration. Building configuration can challenge wi-fi connectivity. Cement walls and oddly shaped and spaced buildings are requiring additional routers and repeaters. This increases costs but may not always address the underline connectivity issue. Cell-enabled, mesh network and field area networks are all expected to address costs and improve connectivity. Expanding the fleet and adding cell-enabled switches will help determine the best switch for each building type.

A.3.4 Managing Cost and Cost Effectiveness

PGE is actively managing total costs of the program in order to positively affect cost effectiveness. PGE is focusing on a few select cost categories to better manage the overall cost of the pilot while not negatively affecting pilot performance. Install and hardware costs are the largest controllable cost centers. As stated above, we have seen a significant installed cost decline since the pilot began. New mobile enabled switches negate the need for PGE to create local area networks within each building site. Mobile switches require less investment from PGE in supporting infrastructure such as Wi-Fi routers and repeaters. This translates to less operations and maintenance costs. We are also actively managing contractor costs for each install.

Another way to manage to cost effectiveness is to increase utilization of the units, uptime or availability of the units and the total verifiable load drop from the unit. Recent cell enabled chips, installed in late 2019 are demonstrating better connectivity, as well as better load drop performance.

Table 15 – Cost Effectiveness: Multifamily Water Heater Pilot

	TRC		PAT		RIM		PCT	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Administrative costs	$14.56		$14.56		$14.56			
Avoided costs of supplying electricity		$12.78		$12.78		$12.58		
Bill reductions								$0.00
Capital costs to the utility	$0.00		$0.00		$0.00			
Environmental benefits		$0.14						
Incentives paid			$11.55		$11.55			$11.55
Revenue loss from reduced sales					0.00			
Transaction costs to participant	$0.00						$0.00	
Value of service lost	$1.19						$1.19	
Sum of costs and benefits	$15.7\5	$17.60	$26.11	$12.78	$26.11	$12.78	$1.19	$11.55
Benefit Cost Ratio	0.82		0.49		0.49		9.74	

A.3.5 *Evaluation*

The process evaluation has sought to assess how well the Multi-Family Water Heaters pilot is operating and to identify potential improvements to program processes, including recruitment, enrollment, data management, installation, and event management. Navigant's Summer 2019 evaluation report was submitted to the Commission through Docket UM 1827 February 12, 2020. The evaluation report highlighted several issues. These included customer acquisition, customer experience, system integration and event results. PGE Staff worked actively in December 2019 and Q1 of 2020 to address these items and gave updates to Commission Staff on the progress of our work.

A.3.6 Moving from Pilot to program

PGE has identified five build factors that a pilot moves through on its evolution to program. Stability of the customer experience, infrastructure stability, grid performance, financial performance and dispatch integration. As each program is individual the assessment of program versus pilot status can be individualistic. For example, the multifamily water heater pilot need not focus its attention on the stability the customer experience as the affected unit dwellers have not demonstrated customer friction with the program and how it interacts with their home appliance. However, multifamily water heaters do need to concentrate on infrastructure stability.

A.3.7 Customer experience

This part of the Multifamily Water Heater program is stable. There are two types of participants in the program. Those who take service from the water heater and those property owners and property managers who enroll their property into the program. In response to Navigant's Summer 2019 Pilot Evaluation PGE will be working to improve communications with property owners and centering communications on the benefits of the program and the technology. PGE will also be working to better inform tenant dwellers that the pilot is operating and what they might notice a box connected to their water heater.

A.3.8 Infrastructure Stability

Infrastructure stability is the primary challenge of the program and once addressed and stabilized can transition to dispatch integration the last factor PGE uses to determine pilot to program maturity.

Several infrastructure stability challenges are being addressed and are addressable. These include communications stability and load drop performance in accordance with planning values. Thus far in Q4 2019 and Q1 2020 PGE has been able to address these two infrastructure stability challenges through the installation and utilization of a new type of hot water heater switch which operates on different load drop protocols and a new cellular communications network.

A subfactor of infrastructure stability is tariff stability meaning that PGE through implementation of the pilot has not received feedback from the operation of the pilot that the tariff needs revision in order to provide optimal service. The Multifamily Water Heater pilot tariff operationally is sufficient however in order to assure controlled growth and Commission oversight of costs the program tariff limits the number of installation and regularly updated with each deferral filing. This approach for now is reasonable until such time as the pilot evolves to address the and stabilize some of the technology challenges and has begun the process of dispatch integration.

A.3.9 Stability of Performance

For multifamily water heaters stability of performance is closely tied to infrastructure stability. As PGE is able to address communication and event performance from the field units.

The PGE team is now working to address water heater performance during the events. The new cellular switches being installed are resulting in better performance per unit.

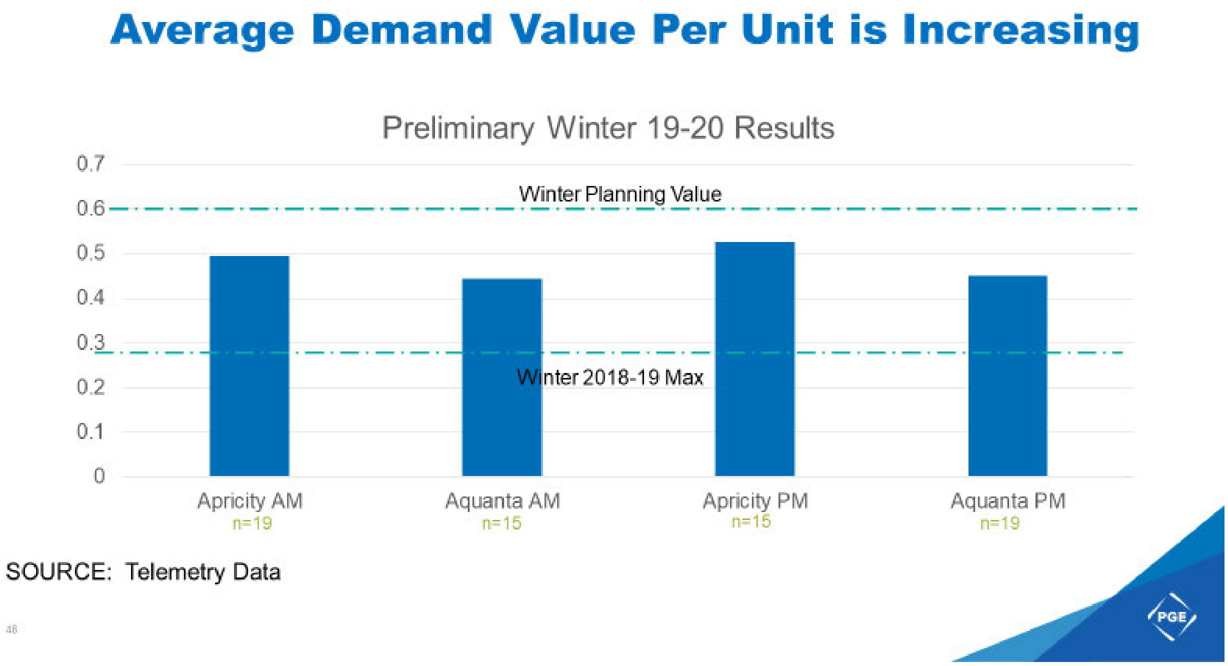

Figure 27 – PGE's Residential Demand Response Pilot Update, January 27, 2020

The figure above demonstrates the increased load drop seen with new approaches to water heater switch performance both for legacy Wi-Fi enabled units and new cellular enabled units. One can see an increase in performance. Additional performance improvements are necessary to meet the original filed planning value.

Dispatch Integration

Events are called daily (Monday-Friday, non-Holidays). Winter events are typically called twice per day for 3 hours each, from 6am-9am and 5pm-8pm. Summer events are typically called once per day for 4 hours from 4pm-8pm. We have found that we need to start and stop all events on the hour to prevent partial event recording.

It should be noted that events are not presently called by power operations. While there is coordination with the PGE Balancing Authority about when events are called and for what duration the pilot at present is too small a resource to hand over dispatch to power operations. Additionally, once the pilot team is able to stabilize the communications and technology performance issues the Multifamily Water Heater team will need to work with Power Operations to create a Mater File and dispatch protocols for utilization of the resource. Once this work begins, the threshold from Pilot to Program has been crossed. The Power Operation team has let the Demand Response team know that the resource must perform within a 12-15% accuracy of the nominated capacity. Thus, multifamily water heaters will need to identify with this same level of accuracy the reliable performance of the total aggregate resource. This means that connectivity of the water heaters needs to be closer to 85% and event participation must similarly in the aggregate meet 85% of the total nominated capacity whether used for multi-hour service or sub-hourly services.

A.3.10 Pathway to Flexible Load

The Multifamily water heater program is PGE's most dynamic demand response resource and is capable of providing true load flexibility with minimal customer service interruptions. Additionally, because of the ubiquity and low entry level cost of the resource the Multifamily Water Heater Program holds significant promise as large service territory wide resource. The lessons learned from the multifamily water heater program will inform our single-family water heater program. It is likely that as the multifamily water heater program is incorporated into power operations it will be the first of PGE's flexible load customer sited residential programs.

A.3.11 Activity within the Testbed

Multifamily Water heater pilot is present in the Testbed. PGE will be using the pilots' presence in the Testbed to help identify the locational value of the resource. PGE will also be looking into how the multifamily water heater program will inform thermostat programs for multifamily units within the Testbed.

A.4 Residential Direct Load Control Smart Thermostat Pilot

Total Costs	Megawatts Procured	Cost Effectiveness Score	Next Evaluation
$5.5M (EOY 2019)	13.7MW	1.06	Summer 2020 (due July 2021)

A.4.1 Pilot Description

The Residential Direct Load Control Smart Thermostat Pilot aims to enroll and operate connected residential thermostats to control electric heating and cooling load. This pilot provides firm capacity; PGE is working with the Energy Trust to explore how thermostats and other efficacy measures can be paired to provide longer duration energy optimization. To participate in the pilot, PGE customers must operate either a ducted heat pump, electric forced-air furnace, or central air conditioner. The pillars of the pilot rest on three delivery channels:

1. **Bring Your Own Thermostat.** Customers may enroll online in PGE's demand response offer by A) purchasing a new qualifying thermostat, or B) using an existing qualifying thermostat attached to a qualifying HVAC system. Customers receive a $25 enrollment incentive and $25 for each DR season that they participate in (defined as 50% of the DR hours called within a season). Customers are permitted to opt-out of any or all events.

2. **Residential Thermostat Direct Installation.** Customers with a qualifying HVAC-system can participate by receiving a qualified thermostat, installed, provisioned, and enrolled into PGE's DR platform by a PGE contractor. This channel provides a no cost thermostat for customers with a ducted heat pumps or electric forced air furnaces, due to the high DR capacity value. Customers with central air conditioners are charged an incremental cost of $50. Customers from this channel are excluded from receiving PGE enrollment or seasonal participation incentives.

3. **Residential Thermostat Direct Ship.** PGE's roadmap for residential thermostat includes a possible new channel in 2020. This new channel would allow PGE customers to go online and order a thermostat free or at a reduced charge. In return, customers are required to self-install and enroll into PGE's DR pilot. Participating customers coming through this channel are excluded from receiving PGE enrollment and seasonal incentives. This channel is currently not yet active or approved–it is scheduled to be available in the Winter 2020 season.

A.4.2 Primary Goals

- The pilot aims having a total of 20,000 residential thermostats by 12/31/2019
- Determine and verify customer acceptance of the above delivery channels
- Build a minimum of 20 MW summer capacity and 2 MW winter capacity,

- Successfully operationalize and maintain or increase customer satisfaction for all three delivery channels
- Dispatch and control enrolled thermostats and obtain DR capacity at or above planning estimates
- Minimize customer drop-outs from *the pilot* (not event-based overrides) to increase customer retention

A.4.3 Market Potential

- This pilot's primary targets are PGE customers with and without existing connected qualifying thermostats that live in single-family residences with ducted heat pumps, electric forced air furnaces, or central air conditioners.
- Based on the best available information, PGE estimates the total number of eligible households is about 326,000 units (total addressable market). This number is increasing due to increasing installations of central air conditioners. The achievable potential is estimated at 149,000 units, which represents approximately **82.5 MW**. PGE continues to refine these estimations by improving our customer heating and cooling data, analyzing which types of customers are likely to be most successful in the pilot (not override their devices during an event) and implementing efforts that support customer participation.

A.4.4 Lessons learned

The Smart Thermostat pilot has identified several lessons learned which have translated into performance and structural items which are being addressed during 2020. Addressing these performance and structural items will advance the pilot toward the program phase. These lessons learned include:

A.4.4.1 Increasing Performance Levels for Direct Install Channel

PGE has identified that enrollees into the direct install channel have demonstrated a higher event override propensity than the Bring Your own Thermostat channel. This may be due to the type of customers who enrolls in the direct install offer. We are conducting further research to determine how best to engage with these non-performers before engaging in claw back activity outlined within the tariff. Our research indicates that customers utilizing this channel are older, typically on a fixed or lower income (retirees). As inability to pay utility bills is an advanced indicator of homelessness, we want to make sure that we are not placing non-performers on a claw back list, taking such action which may have deepen longer lasting negative lifestyle implications. To enhance participation and reduce overrides, PGE is commencing in follow-up educational efforts with Direct Install customers to refresh them on participation requirements and revising the claw back provision to reflect a more equitable solution.

A.4.4.2 Manage the Device Communications Interface

PGE launched the BYOT Smart Thermostat channel in 2015 with Google Nest, the provider of the Nest thermostat, by utilizing Nest's program, Rush Hour Rewards, to recruit customers and control Nest thermostats when PGE scheduled demand response events. This service to control the thermostats is generically referred to as "Distributed Energy Resource Management" or DERMs. This was a relatively turnkey solution for PGE. However, in late 2019, Google Nest informed PGE that they would not be providing their demand response management services in support of the Nest Thermostat following the winter 2019-2020 season. Google Nest provided little explanation stating, "due to Nest's integration with Google and our desire to help these programs scale, Google is shifting the way that RHR programs will be managed". PGE has contracted with Resideo, the current DERMs provider for ecobee and Honeywell thermostats in PGE's Smart Thermostat Demand Response Program to also provide DERMs services for Nest thermostats.

While this transition should have been seamless for the customer, Google Nest has further complicated it by updating their terms and conditions for the Rush Hour Rewards Program. This change requires active acceptance by every existing customer to remain enrolled in the program. If customers decline or fail to accept the new terms and conditions by September 15th, 2020, they will be unenrolled by Google Nest. These events have two implications for the PGE Smart Thermostat pilot: 1) the pilot is likely to see some enrollment reduction this will in turn cost the program in re-recruitment dollars. 2) this has taught PGE that partnerships with a device manufacturer who has so much market power must be approached with a contingency plan. To retain customers, PGE has provided advanced and direct communication to customers about these changes and the actions they must take to stay in PGE's program and retain the benefits. This has created additional administrative costs for the program for customer engagement as well as data management through the migration. For the longer term, PGE is currently investigating ways to create a direct relationship with the customer in support of these programs, rather than relay on third parties own those relationships.

A.4.4.3 Data and Customer Enrollment Management

The PGE customer data management system was not prepared the for the popularity of the Smart Thermostat pilot. IT upgrades needed to collect and track participation, enrollment, event performance and customer incentives did not happen in the necessary succession in order to support the growing enrollment. PGE's IT team is presently working to include these pilot activities into the meter data management system and the customer information and billing system that will allow more automated data management and reduce implementation costs internally (reduce manual data management) and externally (e.g., incentives have been administered through a third-party contractor). Ultimately, this will create a better customer experience as enrollment processes will be more expedient and incentives will be provided more quickly and "on-bill".

A.4.4.4 Low Income Approach

PGE is working to identify how to service low income customers with smart thermostats because the demand response program requires a qualified electric heating and cooling system, a smart thermostat, and reliable internet connectivity. There are two main hurdles to adoption for low income customers:

1) Low income customers may not be able to afford a Smart Thermostat or accommodate an appointment during regular business hours for a direct install offer. PGE is designing the "direct ship" channel to specifically target these customers with a free thermostat that they can install themselves and take advantage of energy efficiency and demand response events.
2) Low income customers experience the technology divide, as 35% or more do not have home internet, lagging behind the national average by 13%[133], and tend to rely on smart phones to access the internet. Through PGE's Smart Grid Testbed project, PGE is working with the City of Hillsboro to leverage the City's Low Income free and lower cost internet program. Progress on this work will be presented to the Demand Response Review Committee the group of stakeholders established by the Commission and PGE to help direct the work of the PGE Testbed.

A.4.5 Managing Costs and Cost Effectiveness

The pilot is continuously working to improve cost effectiveness through managing pilot costs and through identifying ways to increase the demand response performance. Here is a list of key initiatives completed or in process:

- PGE Leveraged the DERMs provider migration from Google Nest to Resideo to negotiate a 10% overall cost reduction for DERMs services across the pilot (assuming a 90% retention rate of Google Nest devices by September 15, 2020)
- Renegotiate Direct Install vendor contract to reflect recent drop in thermostat prices as well as restructure pilot to offer Nest E as no cost offer for all heating systems, reducing overall implementation costs by 12% in second half of 2020
- As previously mentioned, progressively introduce IT upgrades to reduce the amount of manual labor required to manage pilot processes and data as well as eliminate reliance on 3rd party vendor for check cutting services
- Investigate and trial mid-season engagement strategies and increased customer education to create higher participation rates and reduce customer event "override" (planned for Summer 2020)
- Alert customers with "offline" devices to root cause and repair their connections to enable future participation
- Enable automated "moves" process to re-engage customers who move within PGE's territory in the pilot and to ensure that new occupants of previously participating residences are also enrolled in the pilot

[133] https://www.census.gov/library/stories/2018/12/rural-and-lower-income-counties-lag-nation-internet-subscription.html

Table 16 – Cost Effectiveness: Residential Direct Load Control Smart Thermostat Pilot

	TRC		PAT		RIM		PCT	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Administrative costs	18,610		18,610		18,610			
Avoided costs of supplying electricity		25,193		205,195		25,195		
Bill reductions								889
Capital costs to the utility								
Environmental benefits		82						
Incentives paid			20,962		20,962			20,962
Revenue loss from reduced sales					889			
Transaction costs to participant								
Value of service lost	5,243						5,243	
Sum of costs and benefits	23,853	25,277	39,572	25,195	40,460	25,195	5,243	21,850
Benefit Cost Ratio	1.06		.64		.62		4.17	

A.4.6 Evaluation

Evaluations are conducted by a third Party (Cadmus) in which they evaluate the following:

- Pilot Delivery/Enrollment – the how and how many customers who've enrolled
- Pilot Impacts – measuring the demand reductions during the dispatched Summer and Winter events.
- Customer experience – measuring customer satisfaction and comfort levels during dispatched events. Evaluations for the Bring Your own thermostat have been positive thus far which has been filed with the OPUC. An evaluation for the Direct Install channel should be completed and delivered prior to the end of 2019. Also, if approved, an evaluation for a Direct Ship model will follow in 2021

A.4.7 Moving from Pilot to Program

PGE has identified five build factors that a pilot moves through on its evolution to program. Stability of the customer experience, infrastructure stability, grid performance, financial performance and dispatch integration.

A.4.8 Customer Experience

PGE has gaps in the smart thermostat customer experience which need to be addressed. Due to the rapid adoption of the technology and number of units enrolled, PGE Staff have been focused on pilot build. The customer experience needs to be revisited in order to assure a quality customer experience going forward. The highest priority is conversion from separately mailed incentive checks to on-bill credits. This will provide a more expedient connection between customer participation and reward and help lower the administrative costs assisting with the cost effectiveness of the pilot. While much of PGE's outreach has been focused on customer recruitment, we are also working on-going engagement throughout the winter and summer seasons and education of customers, across a diverse set of demographics, to drive better customer satisfaction and success.

Additionally, PGE is working on a pathway to better verification of specific heating and cooling types for eligibility and currently seeking a solution for optimizing HVAC system verification. The Direct Install channels ensure that each customer is enrolled in the correct season, but the BYOT channel relies on a combination of customer testimonial, thermostat OEM data, and publicly available information to ensure eligibility and correct seasonal assignment. Many customers are not knowledgeable about their own HVAC systems so bridging this gap will enable more targeted customer recruitment and reduced customer confusion. Though the AMI meter data is informative of hourly usage it lends no verified insights into how the electricity is being used, thus verification of the HVAC type cannot be verified through the AMI meter data. We are presently work with Bigley and the Energy Trust's contractor Recurve to identify meter data analysis techniques which might better elucidate how customers are using their electricity and how to better enable their success in the pilot.

A.4.9 Infrastructure Stability

We were informed by Google Nest that will no longer be supporting their demand response management system for Nest Thermostats in late 2019, requiring PGE to contract with another provide for DR services. Additionally, , in early April, Google Nest communicated to Nest owners that they must actively accept new terms and conditions in order for Nest owners to remain enrolled in PGE's Rush Hour Rewards program. If the customer does not accept the new terms and conditions by September 15, 2020, Google Nest will unenroll the customer from the program. PGE responded to these changes by expanding the contract with Resideo, the current DERMs provider for Honeywell and ecobee thermostats and on the Google Nest approved list. PGE also alerted customers about this change in advance to better prepare them and supported acceptance through additional customer communications. This process has generated unplanned re-recruitment expenditures to re-capture customers who may have unknowingly unenrolled from the PGE pilot. This significant infrastructure adjustment will need to be addressed and stabilized in order to understand the total on-going cost when the pilot matures to a program.

A.4.10 Stability of performance

Currently we call events in the following manner:

- Review a daily report generated by PGE Power Operations that displays the forecasted load and what time(s) it will be at its peak, the Hi/Low temperature and regional weather, the Mid C Power Peak Price, and Power Plant conditions.
- We then record the above conditions with pre- determined parameters (from consulting with Power Operations) which then highlight/color code if the conditions warrant calling a demand response event.
- If the conditions warrant an event, we then consult with Power Operations to ensure it is okay to dispatch the event
- We then send out the decision report to all stake holders and inform them an event will be called and at what time so that ahead of time so that each area can take the necessary action to enable the dispatch of these resources .
-
- It is thought that once DR pilots become programs, power operations will assume the duties determining and dispatching events.

Predictability of load impact: 12-15% accuracy

A.4.11 Dispatch Integration

PGE will begin to address integration of the Smart Thermostat pilot with PGE's Power Operations and Balancing Authority once we have addressed the DRMS issues we are presently experiencing with Google Nest. Until then PGE will continue the practice of coordination with Power Operations and the Balancing Authority.

A.4.12 Pathway to flexible load

The pathway to Flexible Load for the Smart Thermostat pilot is presently less well defined and understood then the Energy Partner or the demand response enabled water heaters. Two options will need to be explored, likely through small demonstration projects or through model research activity conducted in the Testbed should the Testbed enter a second phase effort. Initially, the thermostat resource can be used for localized grid services in short event bursts (such as 1 hour). Dispatch could also be optimized to compliment renewable resources utilization. This aspect is being tested as a customer value proposition within the Testbed in 2020 and 2021.

Lastly, a combined energy efficiency and demand response measure whereby homes are better insulated may provide additional thermal mass for variable use of the thermostat throughout the day. This concept needs additional work, coordination and exploration with the Energy Trust.

A.4.13 Participation in the Testbed

The Smart Thermostat pilot is an anchor tenant of PGE's Smart Grid Testbed. Lessons learned from its inclusion in the Testbed will inform PGE program design for years to come.

A.5 Non-Residential Demand Response Energy Partner Program

Total Costs	Megawatts Procured	Cost Effectiveness Score	Next Evaluation
$9.8M (Jan 2017 EOY 2019)	21.8 MW	1.23	Q2-2021

A.5.1 Program Description

PGE is piloting a non-residential demand response program designed to reduce peak demand requirements during specific time windows in the winter and summer seasons by incenting customers to reduce their energy consumption during those times. PGE expects the primary source of this reduced demand (load) will be from large customers, with an option for small and medium customers to participate as well. The Energy Partner Program provides firm capacity; this program may evolve to provide intra-hour grid services to support reliability and renewables integration. The 2018 target was 14 MW of DR, increased to 20 MW for 2019, and ultimately to 27 MW by January 1, 2021.

PGE's non-residential DR program was launched in December of 2017, and was directly administered by PGE, with support from:

- CLEAResult for program implementation
- Enbala for technology integration via their Virtual Power Plant (VPP) software platform. PGE took a more active approach than the prior "turnkey" DR program administered by EnerNOC, as PGE found that third party aggregation fell far short of load goals.

The new arrangement offers the flexibility to offer a variety of products and potentially adjust them in the future. The secondary reason for PGE to work directly with customers is portfolio resiliency. With the loss of EnerNOC in 2017, PGE had to execute new contracts and deploy new technology to current participants. This presented customer retention risk. Directly administering the program should avoid such adverse operational risks should a third party exit the program. PGE administration of the program also allows for better bundling and / or cross-marketing of the program with other offerings such as EE, renewables, storage, and dispatchable standby generation.

Delivering an impactful business DR program and the associated flexible load is key to A) delivering upon PGE's IRP commitment, B) supporting Oregon's 50% renewables by 2040 (SB1547) target, and C) enabling PGE to achieve aggressive carbon reduction goals (carbon emissions reduced by 80% below 1990 levels). The program is expected to help us learn how to drive program adoption, optimize the DR software platform, and leverage the program value over time–evolving from a solely capacity resource to other use cases such as load following and renewable firming..

PGE’s previous business DR program was initiated in 2013 and administered by EnerNOC. This prior iteration fell short of its 24 MW DR target, and by the end of 2016 had achieved only 10.6 MW. The volume gaps were attributed primarily to EnerNOC’s approach to program design (inflexible and oriented solely to large customers) and their sales process, which lacked on-site account management. Their model delivered results in other geographies but was not adjusted to meet the needs of PGE’s customer base. PGE’s redesigned program offers customers flexible participation options during events, greater remuneration, options for both large and small-to-medium sized customers, and a “higher touch” sales approach.

In the prior program, customers had to enroll for 40 hours of event time per season and be on call from 7 am to 10 pm in the winter and noon to 10 pm in the summer. In the current program, customers can select from 20, 40, or 80 hours of events per season and customize their participation schedule by selecting one or more event windows such as 7-11 am (winter), and 11 am to 4 pm, 4-8 pm, 8-10 pm (summer and winter). Compensation is also more favorable: the same selections as the prior program now earns 22% more, and the maximum hour / maximum window option pays 76% more.

The EnerNOC program lacked participation options for small-to-medium size businesses. PGE’s updated program offers a smart thermostat free of charge; this unit controls heating and cooling during DR events and pays customers $60 per season if they participate in a minimum of 50% of event hours. Larger Commercial and Industrial customers also benefit from this option, as many have office buildings on site.

Another gap addressed by the revamped business DR program is the addition of dedicated sales representatives and engineering staff (provided by CLEAResult) who can work on site with customers. EnerNOC predominantly serviced accounts over the phone and via email and were unable to build the customer insight and trust essential to success. Unlike residential DR programs which leverage a “mass market” approach, business customers require individualized, ongoing focus to ensure their operations are not disrupted by DR events (e.g. nominations may require adjustments, questions may arise as to how to optimize participation during events).

A final limitation of the EnerNOC program was their DR Management System (DRMS) which was acceptable for the prior pilot but lacked the technical capability to meet future requirements. The tool only supported an “all call” approach, which notified all participants during a multi-hour event. Compare this to Enbala’s more sophisticated VPP, which can call devices based on constraints such as location (e.g. around a feeder), or customer sited set points (maximum and minimum pump set points). The Enbala VPP software used with PGE’s new program provides the flexibility to meet these future needs.

Customer feedback on the redesigned program has been positive. Customers appreciate the flexible program design and dedicated / responsive sales and engineering staff as improvements. PGE is proud that the great majority of customers transitioned to the new program. When combined with additional customers that PGE has signed up for the program, PGE exceeded its 2018 & 2019 targets of 14 MW and 20 MW respectively. A comprehensive Measurement and Verification evaluation of event performance and customer satisfaction was completed in third quarter 2019 with favorable results.

A.5.2 Incremental Activities

The non-residential DR program is expected to entail bolstering several program design elements to accelerate the program's ability to refine and optimize its delivery activities. Specifically, PGE plans for the program's activities to include enhanced incentives, targeted marketing, and dedicated sales / outreach. We expect these efforts will be incremental to the program's "business as usual" operations, meaning that they leverage existing program activities. Furthermore, we expect these incremental efforts to be invaluable in defining optimal program delivery strategies and tactics, identifying customer segment-specific ceilings for program participation, and facilitating acceleration of significant load reduction capacity within the DR portfolio.

Examples of potential incremental program activities evaluated include:

- Incentives
  - Offering enhanced incentives at a to-be-determined level
  - If possible, testing multiple enhanced incentive levels is desirable due to ability to determine "incentive elasticity"
- Marketing
  - A/B testing of the same messaging delivered through different delivery mechanisms
  - A/B testing of customer segment-specific messaging
- Sales / outreach
  - dedicated sales / outreach staff
- Product design
  - Bundling of program offerings such as business demand response electric vehicle charging and Energy Trust's Strategic Energy Management.
  - New tariff designs that allow the customer to provide differentiated energy services throughout the year for a greater number of total hours of the year.
  - Tiered incentive levels tailored to the DR approach (e.g. manual, automated, or advanced)

PGE intends to leverage non-residential DR program activities to drive improved program performance on a territory-wide basis. To enable this, the program expects to have informed answers to the following questions:

- By customer size and segment:
  - What incentive levels are most cost-effective at driving program participation?

    - Which product bundle and marketing messages are most compelling?
    - What is the maximum expected conversion rate given various incentive / marketing / sales / outreach configurations?
    - Are marketing, sales / outreach, or incentives most impactful in driving program participation?
- Which customer segments are extremely *unlikely* to participate (regardless of incentive level) due to operational challenges not conducive to DR participation?
- Is sales / outreach or targeted marketing more effective at converting small-to-medium sized customers?
- Do customers have a higher propensity to participate if businesses located near them are also participating?

PGE expects that evaluating the non-residential DR program's learnings will improve our ability to fine-tune DR offerings in both the small-to-medium business (SMB) and large commercial and industrial spaces.

A.5.3 Goals

The goal of the Energy Partner Program is to provide 27MW by end of year 2020. Additionally, the Energy Partner program is the most mature program in the PGE demand response/flexible load portfolio. PGE is currently working with our power operations team and our balancing authority team to incorporate Energy Partner into power operation dispatch practices, such that Energy Partner is seen agnostically, as a resource within the resource stack and dispatched based on its operating profile. The process for this integration has started. Below is a diagram which maps our current Energy Partner dispatch practices and protocols.

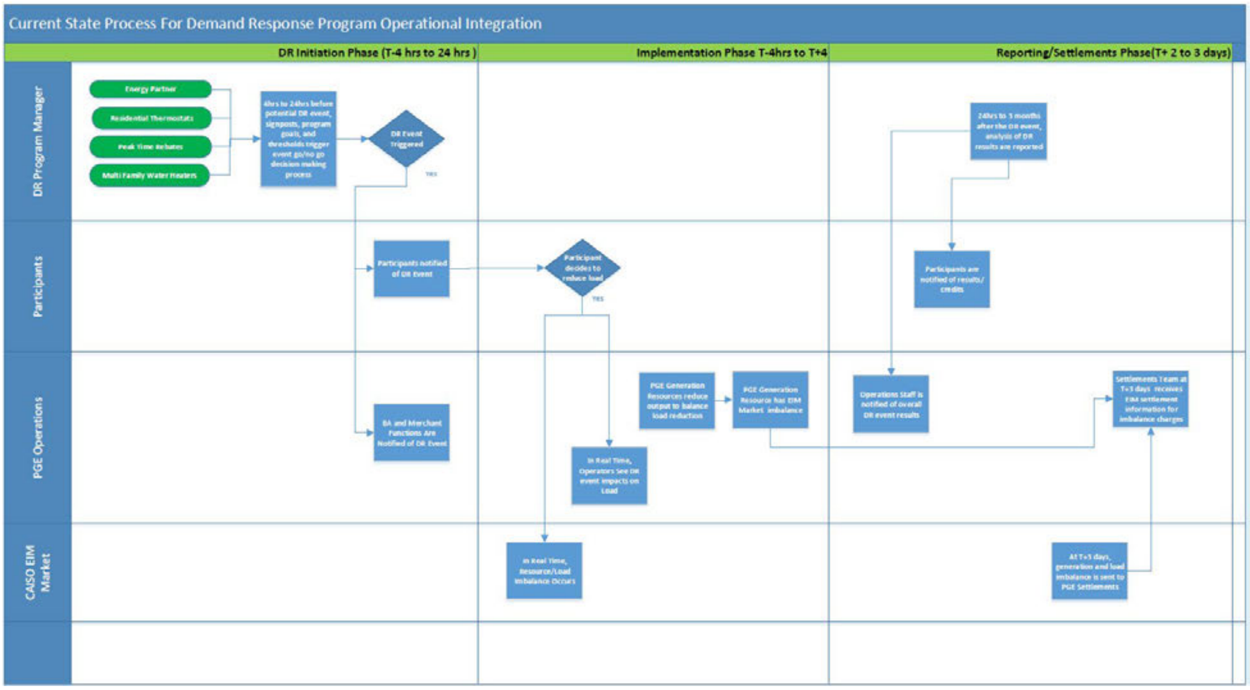

Figure 28 – Energy Partner Program Operation Integration – Current State

The most immediate takeaway from the diagram is that 1) Energy Partner is not dispatched by power operations but is dispatched by the program operations group. This practice is the result of an earlier Commission decision requiring dispatch of the program the for a certain number of times per year. This means the program is not dispatched economically but dispatched for program development purposes. While this practice serves an important purpose for both PGE and participant customers; after Energy Partner transitions to power operations this resource must be dispatch based on power operations set criteria for grid stability and economic efficiency. 2) Second the full integration of Energy Partner into power operations will require process changes to both power operations, the program operations group and Energy Partner. This would include communication to the participants about the change and how it may or may not affect them and their expectations.

PGE has been working cross functionally with the Power Operations Team and the Balance Authority Team to develop an approach to flexible load dispatch. Using the process graphic above as the current state; the following graphic was developed to show necessary process changes. These would then guide the Teams work to include flexible load as a resource within the resource stack, operated as any other resource, dispatch to meet economic and grid stability needs.

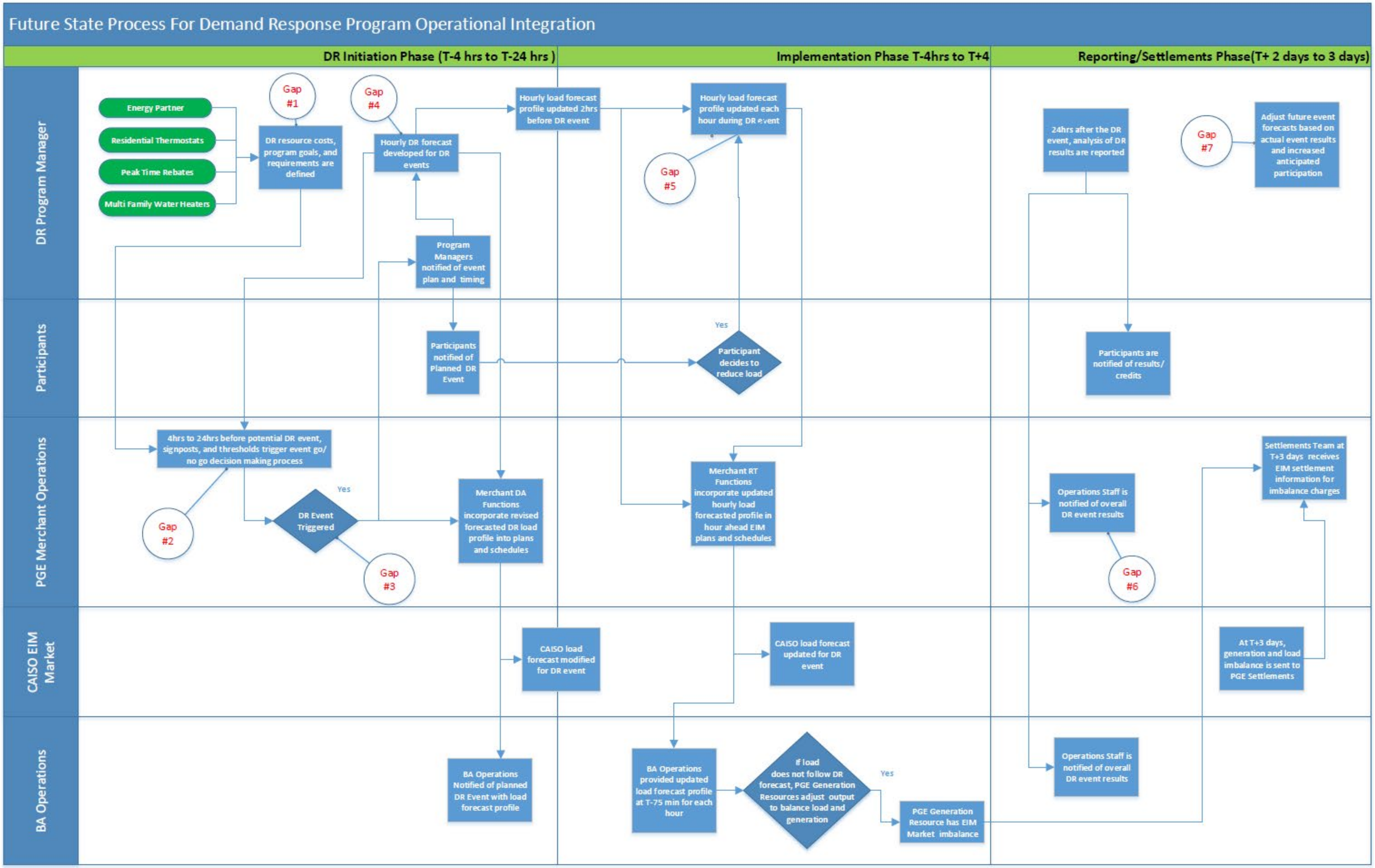

Figure 29 – Energy Partner Program Operation Integration – Future State

The above chart is meant to guide PGE's work to place flexible load into the power operation activity. The chart identifies seven gap areas and recommendations for action.

A.5.4 Demand Response Operational Integration Gaps Summary

Gap #1: DR program operations parameters need better definition, clarity and visibility.

Recommendation: DR Program Managers define overall program costs, incremental dispatch cost, must run requirements, and other program goals, and sign-posts important to the economic dispatch trigger process.

Gap #2: The DR event trigger process should be better defined for economic dispatch and the go/no go decision-making process should lie with Merchant Operations.

Recommendation: DR Program Managers and Operations Leads partner to define the economic dispatch signposts and thresholds that will be used to trigger DR event go/no go decision-making process.

Gap #3: The final decision to trigger a DR event for economic dispatch should be made by Merchant Operations using the appropriate parameters, thresholds, and sign-posts.

Recommendation: Merchant Operations partners with DR Program Managers to stand up decision-making process for economic dispatch of DR event.

Gap #4: DR load reduction hourly forecasts for each event are not part of the current process.

Recommendation: DR Program Managers work to develop process for providing hourly DR forecasts for the entire event duration of planned and future DR events.

Gap #5: DR event load reduction real time monitoring is not part of current process.

Recommendation: DR Program Managers work to develop process for gathering real time information on actual load reduction and provide updated forecast for remaining duration of the event.

Gap #6: After the DR Event Results Summary is needed to provide program managers and operations staff updated information for settlements analysis and next event planning.

Recommendation: DR Program Managers develop process for providing complete DR event results summary a minimum of 48 hours after the conclusion of the event.

Gap #7: Past event results and changing customer participation should be used to modify DR Program parameters and forecasts to enhance the future DR event trigger process.

Recommendation: DR Program Managers to develop process for updating key DR parameters for future program enhancement.

A.5.5 Market Potential

Energy Partner is a two-tariff program operating under both Schedule 25 and 26.

The chart below is from the 2016 'Demand Response Market Research: Portland General Electric 2016 to 2035' report prepared by the Brattle Group. The chart shows the potential MW reduction for various DR program designs in PGE's service territory. The load reduction potential of each program design was evaluated in isolation from each of the other options; they do not account for potential overlap in participation that may occur if several DR options were simultaneously offered. What also should be noted is that the potential MW reduction estimates include all customers in PGE's service territory and do not account for direct access customers who currently are not eligible to participate in PGE's demand response programs. This will have a significant impact on the market size for programs targeting the large C&I customers. In addition, the chart has been updated from the original report to show the current level of enrollments for the Schedule 26 (20.7 MW) and Schedule 25 (0.2 MW).

For Schedule 26, the program design on the chart that most closely correlates to the current Energy Partner program is the 'Large C&I Curtailable Tariff, Opt-In' (second from left) which is estimated to grow to 70 MW. Derating that number by 50% to account for non-qualified direct access customers would indicate a market size of approximately 35 MW.

For Schedule 25, the 'Medium C&I' program designs on the chart do not correlate with the current Schedule 25 program design, which makes it difficult to estimate market size. However, the number of small and medium business in PGE service territory is a known quantity, approximately 95,000, assuming we enroll half those customers and applying a conservative KW impact of .3 KW for each one, the potential market size would be around 15 MW.

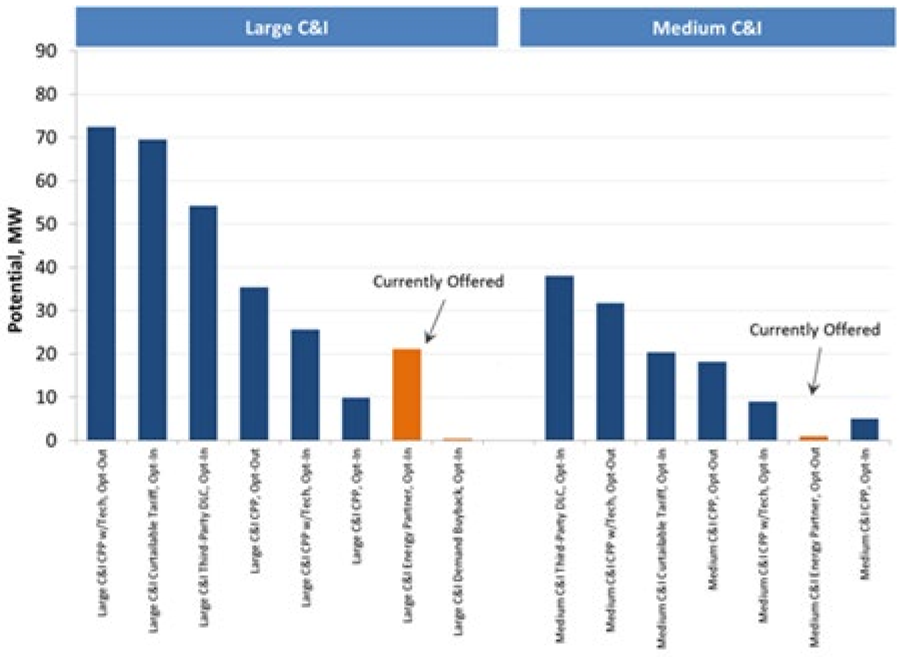

Figure 30 – Potential MW Reduction for Various DR Program Designs

A.5.6 Lessons Learned

A.5.6.1 Pilot Performance can be affected by one customer

In summer 2016 customer nominations ranged from 50 KW to 1.1 MW and the six customers with the highest nominated load reductions accounted for 48% of the total. Enrollment and nomination changes from these larger customers have a greater impact on the total nominated load than an average per participant number suggests. For example, one of the customers that we lost due to direct access was a national retailer with ten stores in our service territory. When that one customer transitioned to direct access at the end of 2016, we lost all ten stores, 1.1 MW of nominated load or about 12% of total load at that time. Adjustments and unenrollment's to a single nomination from a large customer will cause much greater impacts to the total nominated load than an average load per customer would suggest.

A.5.6.2 Program Stability should not be in the control of contractors

The previous program implementer, EnerNOC, opted to leave the program at the end of the summer 2017 season". Updated information on the subject was included in the 2019 report; "EnerNOC, Inc. and PGE ended the aggregator contract in September 2017" and "PGE contracted with CLEAResult Consulting Inc. to coordinate the customer enrollment and enablement process and with Enbala Power Networks, Inc. to provide the demand response management system (DRMS)". It's was a mutually agreed transition because EnerNoc acted as an aggregator focused only on load and could not deliver the required realization rates. Under the new format, PGE modified the tariff (Schedule 26) to provide more options to customers and assure delivery of both load and realization.

During the winter 2017 season a significant load reduction was caused by the transitioning of the program away from EnerNoc to new implementors, CLEAResult and Enbala. On September 30, 2017, the end of the summer season, every participant was automatically unenrolled from Energy Partner and then PGE, along with the CLEAResult, reached out to each customer to re-enroll them in the program. At the end of 2017 PGE had re-enrolled 3 MW. By the summer season 2018 PGE had enrolled 12.5 MW back into the program. At no time under the EnerNoc contract did this program see such rapid growth

A.5.6.3 Tracking Enrollments based on nominated MWs per customer is a poor metric

Although tracking the pilot using a MW per participant metric is a reasonable way to identify early trends and inflection points (i.e. the program transition it doesn't effectively capture details that have impacts to enrollments and total load. Moving forward this metric will become even less effective because of the way enrollments are targeted. The initial focus of the program was to target and enroll customers with the largest loads to get the biggest initial impact, once those large opportunities are exhausted customers with smaller loads will be targeted. As enrollments for smaller customers increase the MW per participant metric will decrease and may lead to an assumption that there is a problem with the program when it's just a reflection of the way nominated loads are distributed among customers.

A.5.6.4 Moving from Pilot to Program

As noted above efforts are underway internally to transition Energy Partner to power operations and PGE has identified the factors indicative of a pilot to program transition. Discussion of the additional factors can be found below.

A.5.6.5 Customer Experience

The customers enrolled in Energy Partner are larger sophisticated energy consumers. Many have been part of the program for the last several years. These customers have responded to events and have demonstrated very stable performance and understanding of how to respond to events and signals. As Energy Partner is transitioned there will be a need to communicate any program changes to these customers.

A.5.6.6 Infrastructure Stability

The Energy Partner program has a well-known and operating supporting infrastructure which includes a third-party Demand Response Management System. Additionally, through the PGE portal Energy Partner participants can view their performance in near real-time. Dispatch call protocols are well practiced with customers. Our contractor CLEAResult has worked with each customer to perform performance audits.

A.5.6.7 Grid Performance

Since program revisions in 2017 Energy Partner has demonstrated load drop stability. Performance of the resource has remained within the 15-20% of nominated capacity.

Financial Performance

The resource is cost effective as presently constructed and operated.

Table 17 – Cost Effectiveness: Non-Residential Demand Response Energy Partner Program

	TRC		PAT		RIM		PCT	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Administrative costs	$8.21		$8.21		$8.21			
Avoided costs of supplying electricity		$17.79		$17.79		$17.79		
Bill reductions								$0.22
Capital costs to the utility	$0.00		$0.00		$0.00			
Environmental benefits		$0.01						
Incentives paid			$12.55		$12.55			$12.55
Revenue loss from reduced sales					$0.22			
Transaction costs to participant	$0.00						$0.00	
Value of service lost	$6.28						$6.28	
Sum of costs and benefits	$14.48	$17.81	$20.76	$17.79	$20.98	$17.79	$6.28	$12.77
Benefit Cost Ratio		1.23		0.86		0.85		2.04

Dispatch Integration

As noted in the above sections PGE is actively working internally to incorporate Energy Partner directly into power operation such that the resource can be economically dispatched.

A.6 Flex 2.0 - Peak Time Rebate & Time of Use

Total Costs	Megawatts Procured	Cost Effectiveness Score	Next Evaluation
$3.9M (2020)	6.9MW	0.84	Estimated March 2022

A.6.1 Pilot Description

In 2016, PGE launched a two-year Residential Pricing Pilot (Flex 1.0) in which a combination of 12 opt-in and opt-out TOU, PTR, and Behavioral DR scenarios were tested. Flex provides energy optimization by shifting use out of high demand periods and provides peak reduction through a modification of the demand forecast. In all, approximately 14,000 customers were enrolled in control or treatment groups and provided valuable insights into customer response to, and expectations of, programs of this nature. In June 2018, Cadmus completed an independent evaluation of the Flex 1.0 pilot and confirmed that PGE can cost-effectively obtain demand savings through pricing and behavior-based DR programs and offered specific recommendations on those scenarios that delivered the highest value and levels of customer satisfaction.

Based on those findings, PGE worked with OPUC staff and stakeholders to develop the Flex 2.0 "Residential Pricing Program" that we believe will achieve high customer satisfaction and support PGE's DR goals. The goals for Flex 2.0 are as follows:

- Design and deploy a large-scale DR program that equitably and cost-effectively contributes a substantial DR amount to our IRP goals.
- Offer easy-to-engage-in DR offerings that serve as gateways for adoption of other DLC offerings such as Smart Thermostat.

The first step of Flex 2.0 was launch of a PTR pilot in April 2019. The vast majority of PGE's residential customer base is eligible to participate in this voluntary pilot, and 77,000 residential customers have chosen to enroll in the past year (opt-in basis) exceeding our Year 1 enrollment goal by 40 percent. The PTR pilot provides educational energy saving tips and rewards customers for shifting their energy use during 3-4 hour "event" periods when energy costs are higher and renewable energy sources are less plentiful. Customers are notified a day prior to the event via text and/or e-mail, based on their preference, and encouraged to shift usage during the event hours the next day. After the event, they are notified of the result of their specific effort and, if applicable, their earned incentive. Customers earn $1.00 for every kWh they shift during an event, and the rebate appears as a credit on their next monthly bill. There is no "penalty" should a customer use more than expected energy during an event, making PTR a no-risk, "win-only" offering for our customers. The pilot uses to third party service providers: Oracle delivers the pre- and post-event information to customers and Trove Analytics calculates aggregate and per customer load shift for each PTR event.

PGE is working with OPUC Staff on design of a new TOU rate and plans to submit a revised Schedule 7 tariff to include the new pricing structure in Q2/Q3 2020. The TOU pricing plan could be combined with the PTR to enhance year-round savings and provide daily load shift value to PGE.

A.6.2 PTR is Foundation of PGE's Smart Grid Test Bed

In July 2019, approximately 13,400 customers within the Test Bed were automatically enrolled (opt-out) in PTR as part of Schedule 13. The primary reasoning for this approach was to allow PGE to study customer engagement and participation by testing several customer value propositions. This work is overseen by the Demand Response Review Committee established by the Commission in Order 17-386. Additionally, the Test Bed provides an opportunity for PGE to learn if PTR incentives serve as a "gateway" to other DLC options by fostering behavioral changes that encourage adoption of additional DR offerings.

If an opt-out strategy proves successful within the Test Bed, PGE may explore an opt-out PTR offering with targeted customers or geographic areas. Large-scale participation in programs of this nature provides the opportunity for significant DR load shift, an alternative to additional fossil fuel-based energy plants, as well as supporting PGE's DR goals.

A.6.3 PTR as Part of PGE Decarbonization Strategy

PTR, though a behavior-based load shifting strategy, is part of PGE's decarbonization strategy as it allows us to communicate with customers about when the costliest time to use electricity occurs. These times generally correlate with high carbon content resource procurement or dispatch. Within the Test Bed, PGE is testing Customer Value Propositions in which customers are informed of the carbon resource dispatch deferral they affected through their action. This is communicated as carbon abatement resulting from the aggregate action of Test Bed participants.

A.6.4 Enrollment Goals

Flex 2.0, including enrollment across PTR and TOU treatments in the Flex 1.0 pilot ranged from 3% to 6% despite restricted marketing efforts given the nature of the pilot. In setting enrollment targets for Flex 2.0, PGE assumed increased marketing outreach while still using a conservative adoption rate of 7% year 1 (2019), with 9% growth in year 2 (2020), 4% growth in year 3 (2021) and a more modest 3% growth year-over-year thereafter. Other utilities, such as Sacramento Municipal Utility District, achieved enrollment targets as high as 16% for its TOU program. Enrollment goals are also designed to support our IRP goals for residential DR with more aggressive marketing occurring in the first two years of the program to support that DR goal.

During the first year of broad-scale pilot operations (2019), PGE worked with TROVE Predictive Data Science to analyze *customer-level* earning potential and created Demand Response-specific customer profiles or personas based on that data. While the Flex 1.0 evaluation looked at load shift and DR value at the *aggregate,* averaging performance across the enrolled population, we now have greater insights into *customer-level* load shift and savings potential. We discovered that customers cluster into five unique "savings" groups based on household construct and behavioral factors. We also learned that customers in the highest saving persona classification have potential to shift approximately three times the kWh per event as does customers categorized as a lower saving persona. These lower-saving customers, who were recruited via our Call Center, are over-represented in our current enrollment mix while higher-saving customers are underrepresented, and all customer segments are currently under performing based on their savings potential.

This concept of potential is incredibly important as it points to opportunities where customers *could* earn higher rebates if they had better savings tips and remembered about the event on the event day – both of which PGE can help influence. Given what is now known about these personas, we can tailor more personalized, relevant tips to help customers in each of these segments maximize their potential savings. Additionally, while Flex 2.0 is all-inclusive open to all (unlike Flex 1.0 that enrolled only those customers who would be known savers), we are targeting more high-saving customers through targeted recruitment channels to join to increase overall DR value and improve our cost effectiveness. We believe controlled growth and helping all customers achieve their savings potential will improve customer satisfaction, DR value, and cost effectiveness. PGE has submitted a tariff update to OPUC requesting an enrollment cap extension to 160,000 customers to help support that goal.

PGE had expected to launch the new TOU rate shortly after the PTR in 2019. Feedback from the OPUC and continued collaboration on the rate design has delayed that introduction. Enrollment targets for TOU will be reassessed once the proposed rate design has been approved by the OPUC and market introduction date can be reset.

After initial DR education and awareness, PGE will communicate information about TOU+PTR and encourage customers to stay on PTR or move to a DLC offerings, specifically our Smart Thermostat offering. DLC programs capture larger DR loads and are automated, which presents fewer hurdles to event participation, a more streamlined customer experience, and have energy efficiency benefits. Therefore, transitioning customers to DLC will be key to prove the resource capability of DR. DR initiatives such as PTR, TOU and BDR - with relatively low barriers to entry for customers - can serve as a launching point for drawing residential customers into deeper DR engagement over time.

A.6.5 Market Potential

PGE has identified the achievable potential for PTR and is working to meet the enrollment and saving targets found in the following table.

Table 18 – PTR Market Potential

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
TOU + PTR	19,000	43,000	57,000	66,000	75,000	80,000	84,000	88,000	93,000	97,000
PTR	36,000	87,000	111,000	125,000	139,000	146,000	152,000	159,000	166,000	172,000
Total	55,000	130,000	168,000	191,000	214,000	226,000	236,000	247,000	259,000	269,000
AAGR		136%	29%	14%	12%	6%	4%	5%	5%	4%
% of Res Acounts	7%	16%	20%	23%	26%	27%	28%	29%	30%	31%
MW Impact	16.3	38.8	50.3	57.4	64.3	67.7	71.0	74.3	77.6	80.9

In 2019 PGE was unable to launch the TOU + PTR option found in the table above as filed in ADV. 19-03. The megawatt, although current enrollment in PTR is closer to 90,000 the capacity demonstrated is closer to 14MW. PGE is actively working to launch the TOU and TOU + PTR option in 2020. We have kept Commission Staff updated as to challenges identified since launch and how we are addressing those challenges.

A.6.6 Lessons Learned

To date, Flex 2.0 is not demonstrating the expected load shift reduction/savings per customer as seen in the Flex 1.0 pilot. For the summer 2019 season, PTR events achieved average demand savings per participant between 0.05 kW (5%) and 0.14 kW (8%) for non-Test Bed participants, and 0.02 kW (2%) and 0.08 kW (4%) for TB participants over the season. Overall, load shift is about 60% less than expected based on Flex 1.0 performance results. In analyzing the information received through the summer 2019 and winter 2019/2020 events, PGE has determined several factors contributed to the lower performance results and has already implemented several changes in preparation for the summer 2020 season. Here we describe our findings as well as the improvements we have or will be implementing for summer 2020.

A.6.6.1 Customer Event Notifications

Survey and participation data from summer 2019 indicated that the lack of two specific features offered in Flex 1.0 but not in Flex 2.0 contributed to that decline: enrolling multiple household members for event notifications and same-day event reminders. An end-of-season summer 2019 survey found 25% of customers forget about the event on the event day without a reminder. While PGE is still working to identify a technology solution for enrolling multiple customers in the same household and for dispatching same-day text messages, we do plan to introduce same-day email notifications in summer 2020 and expect this will increase participation and overall load shift.

A.6.6.2 Customer Experience

Cadmus conducted an end of season experience survey following the inaugural 2019 PTR summer season that indicated customers have high satisfaction: 76% of customers who responded (n=953) said they were satisfied, while 34% said they were delighted with PTR. However, when asked more detailed questions about their experience, some customers indicated confusion over how their rebates were calculated and confusion as they perceived that like actions did not yield like results between events. In partnership with our analytics vendor, Trove, PGE reset the baseline approach for winter 2019/2020 to provide a more explainable methodology and create better customer consistency. Customers will feel more encouraged to continue participating in events when they are repeatedly rewarded for their efforts, event to event.

In our surveys, customers also cited that more education and recommendations about how they could shift their load would be beneficial. Some customers reported taking “low impact” actions such as turning off lights or unplugging cell phones as their primary load shift strategies. PGE conducted virtual focus groups in April to gain additional insights about how customers may be able to benefit from more information. As a result, PGE has created new collateral to better explain what specific actions to take during a Flex event. This collateral provides savings tips for both low-impact and high-impact customers and delivers the information in a way that allows the customer to select the tips that apply to their specific household. This approach will enable customers to adjust their energy use based on the options they have within their household and help them achieve their maximum savings potential.

A.6.6.3 Customer recruitment

As mentioned above in the enrollment section, we have learned that our recruitment strategy needs to be tailored to attract customers with the highest propensity for successful participation. While Flex 2.0 will remain open to all customers, PGE is tailoring its marketing approach to focus on customers with the highest propensity to save energy through making event based behavioral changes.

A.6.6.4 Vendor performance

One additional area that affected event performance were errors in issuing event notices by our vendor, Oracle early in the summer 2019 season. Oracle has assured PGE that they have put the proper measures in place to avoid such errors going forward and provide event by event metrics.

A.6.6.5 Investigate other rebate models

PGE is exploring new customer value propositions within the Smart Grid Test Bed that reward customers for behavioral change in different ways such as ability to donate rebates to a charitable organization and through gamification and contests to see if these additional approaches yield more DR savings and better customer satisfaction

We will be monitoring the impact of the above actions by analyzing per-customer DR value closely in the coming seasons and are focusing our efforts on continuous improvement to help each customer reach their savings potential.

A.6.7 Managing costs and cost effectiveness

The table below shows the present state of Cost Effectiveness for PTR and the pilot is currently falling short of our cost effectiveness goals driven mainly by the lower DR value per participant from Flex 2.0 as compared to Flex 1.0. The Flex 2.0 PTR pilot, having only one season at scale with multiple events, is still in development. We have used the information and results achieved to implement multiple measures that should improve pilot performance starting summer 2020, as described in the “Lesson Learned” section and also summarized here:

1) Improved event notifications (adding same day)
2) Increased baseline “explainability” and event to event consistency
3) Updated customer collateral, customized for the audience
4) Revamped customer recruitment strategy
5) Managing vendors for increased performance
6) Testing additional motivational strategies in the PGE Test Bed

In addition to the measures implemented to benefit DR value, PGE is also continuing to manage costs. As noted in PGE’s original proposal in ADV 19-03 PGE has employed TROVE and Oracle to deliver 3rd party services for PTR. On an ongoing basis, PGE evaluates those vendor contracts and looks for opportunities to identify cost-saving measures.

Table 19 – Cost Effectiveness: Peak Time Rebate

	TRC		PAT		RIM		PCT	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Administrative costs	$10.68		$10.68		$12.92			
Avoided costs of supplying electricity		$13.48		$13.48		$13.48		
Bill reductions								
Capital costs to the utility	$2.66		$2.66		$2.66			
Environmental benefits		$0.00						
Incentives paid			$10.77		$10.77			$10.77
Revenue loss from reduced sales								
Transaction costs to participant	$0.00						$0.00	
Value of service lost	$2.69						$2.69	
Sum of costs and benefits	$16.03	$13.48	$24.11	$13.48	$24.11	$13.48	$2.69	$10.77
Benefit Cost Ratio	0.84		0.56		0.56		4.00	

A.6.8 Evaluation

PGE has contracted with Cadmus to provide seasonal evaluations during the first two year of both PTR and TOU. As those evaluations are finalized, a copy of the reports will be filed with the Commission and PGE staff, and Commission Staff will meet to share results and open discussion regarding the findings and potential next steps.

A.6.9 Moving from Pilot to Program

PTR is our newest system-wide customer offer. It is also our first behavior-based DR resource. At present, as stated in the above Lesson Learned subsection, PGE is working to address several challenges associated with the market release of a large behavioral-based offer. The factors associated with pilot to program migration center on: Customer Experience, Infrastructure Stability, Grid Performance, Financial Performance, and Dispatch Integration. Our Residential Team is actively working to address the main challenges such as communication to the customer to enhance event performance and baseline performance and accuracy.

A.6.9.1 Infrastructure Stability

The Team has been able to address a sub-factor of Infrastructure Stability as the billing and data management are well understood and are presently operating well. PGE is exploring how it might reduce costs here by internalizing some of the data management activity which is currently outsourced.

A.6.9.2 Grid Performance and Dispatch Integration

PTR has a 2019 savings goal of 16MW, per the proposal in ADV 19-03. Despite delay in releasing a TOU+PTR offering, baseline accuracy and day-of notification challenges, PTR did acquire 14.1MW by 2019 year end. PTR is PGE's only behavior-based resource. As has been noted in many of PGE's DR and Smart Grid Test Bed filings, behavior-based resources are not the preferred DER resource structure or characteristic power operations prefers. Behavior-based programs are excellent customer inclusive offerings. However, they do not offer power operators the control and certainty power operators prefer. Thus, integration into power operation dispatch will present novel challenges. PTR has several structural challenges which need to be addressed prior to contemplating integration into power operations, but it is PGE intention to integrate each of our Flexible Load offerings.

A.6.9.3 Financial Performance

Peak Time Rebate is a cost-effective resource. We'll need to be careful to assure that changes made to meet challenges faced in the field or offer structure do not jeopardize cost effectiveness.

A.6.10 Pathway to Flexible Load

PTR is a demand response pilot used to address peak usage hours. At present, there is not a known pathway to increase the number of usage hours or to transition the grid service provided, capacity, to a more dynamic energy service. The Test Bed is exploring ways that PTR can be the launch pad of a customer migration strategy to more dynamic flexible load offerings such as thermostats, behind the meter energy storage, and advanced smart water heaters. The Test Bed activity is being evaluated on a rolling basis the lessons learned and the evaluations are shared with the Test Bed's Demand Response Review Committee. If the approach of using PTR as part of customer migration strategy proves valid within the Test Bed, PGE will work to incorporate such into the broad portfolio strategy.

A.6.11 Activity within the Test Bed

PTR operates on an opt-out or automatic enrollment pilot within the geographic boundaries of the Testbed. All residential customers who qualify (do not have a do not communicate requirement on their account or have communicating meter) are enrolled in Peak Time Rebate. Of the roughly 19,000 residential accounts in the Test Bed roughly 15,500 are eligible to participate in PTR.

The Test Bed, across its three substations and cities, has 15,542 residential customers enrolled in PTR. PGE has been working to learn more about who these customers are and how they are motivated to take action during events. Directly connected to PTR in the Test Bed is the Test Bed Team's work to test several customer value propositions to garner insights into customer engagement and performance. For those roughly 15,500 customers enrolled, they will be exposed to four customer value proposition treatments; monetary incentives, carbon reduction, renewable power, and giving back. If any of these value propositions prove effective PGE will use them throughout the service territory first through Flex 2.0. Test Bed is also using PTR because the offer is inclusive as the customer need not purchase any enabling technology to participate. Additionally, PTR does not harm those who are unable to take action or actually use more than expected during an event.

A.7 Residential Battery Energy Storage Pilot

Total Costs	Megawatts Procured	Cost Effectiveness Score	Next Evaluation
$66K (EOY 2020)	160kW	N/A	Est. June 2021

A.7.1 Program description

In April 2020 PGE filed a tariff to leverage battery energy storage systems installed on residential customer homes behind the utility electric meter as a dispatchable resource. PGE is utilizing the pilot to test the capability of residential battery storage to provide a variety of grid and customer services.

As a fleet, the batteries will act in aggregate to provide system services and individually for customer services. PGE has modeled the value of some services; for others, the pilot will seek to establish a value. Each battery will provide between 3 to 6 kW of power output and 12 to 16 kWh of energy storage. The pilot intends to aggregate 525 residential batteries totaling 2 to 4 MW in size and 6 to 8 MWh in duration.

PGE will have full control over battery operations and will charge and dispatch the fleet according to system needs, except in the event of an outage when the batteries will autonomously island to provide home energy back-up. PGE will deploy batteries for the following use cases:

- Distribution use cases:
    - Localized demand response
    - Autonomous Volt/Var support
- Generation use cases:
    - Generation capacity
    - Energy resource optimization
    - Contingency reserves
    - Autonomous frequency response
- Customer use case:
    - Outage mitigation

PGE has selected EPRI's open-source Storage Value Estimation Tool (StorageVET®) software for evaluation and will share modeling results and data. The software co-optimizes bulk system and locational benefits based on provided inputs. This modeling will inform PGE's operation of the batteries.

A customer who applies to participate with a qualified battery and who is accepted into the Pilot will be compensated $40 per month, or $20 if the battery is restricted to rooftop photovoltaic charging only, in exchange for allowing PGE to operate the battery for grid services. All batteries will be owned by the customer. PGE will make the pilot offer available to Community Emergency Response Team ("CERT")/Neighborhood Emergency Team ("NET") volunteers. These trained volunteers have committed to assisting their community in the event of a major disaster.

Customers living within the Test Bed, as defined in PGE rate Schedule 13, with a newly installed qualified battery are also eligible to receive a rebate at time of purchase, in addition to the monthly payments. This offer seeks to drive density within select substations to achieve sufficient technology penetration to test locational benefits.

PGE is also partnering with the Energy Trust to address potential barriers to residential storage for income-constrained customers. Income-qualified customers participating in the Energy Trust's Solar Within Reach program and who install a qualified battery, are eligible for a $5,000 rebate in addition to the monthly payments. These customers may reside anywhere within PGE's service territory.

A.7.2 Residential Energy Storage as Part of PGE Decarbonization Strategy

Battery storage is a potential gamechanger for deep decarbonization of the electric gird. They are capable of providing all the grid services necessary to balance high renewable penetration. Additionally batteries imbedded in the distribution system are able to provide location specific services.

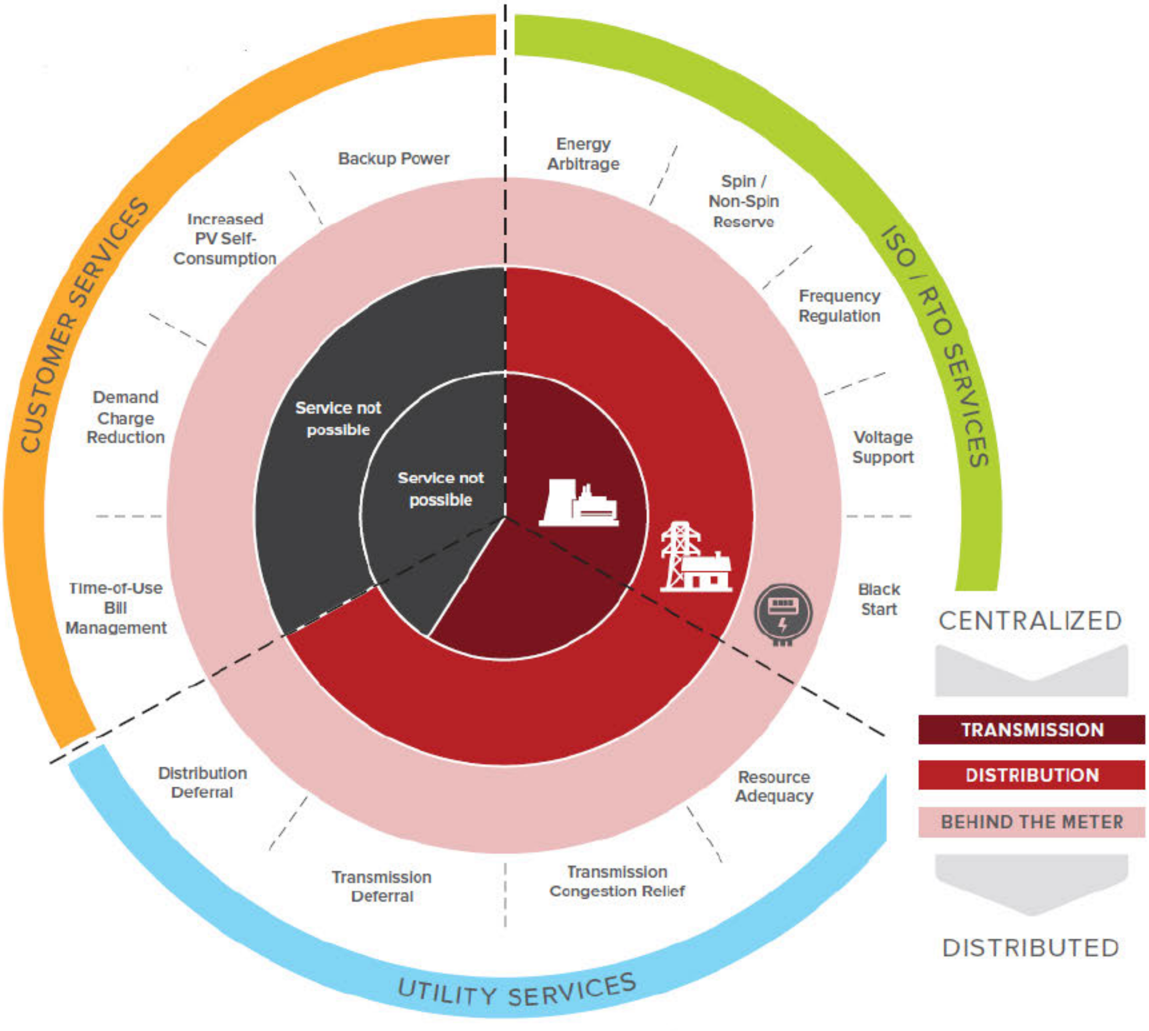

Figure 31 – Energy Storage Services

A.7.3 *Goals*

The key objective of the Residential Battery Storage Pilot is to collect as much information as possible about the impact of residential battery storage in four categories: The Energy Portfolio, the Grid, the Customer, and the Program. These learnings are explored in further detail in the section: Lessons to be Learned.

A.7.4 *Market potential*

PGE's goal is to enroll 525 units for the Pilot in order to have sufficient storage capacity to provide 1 MW for a 4-hour period to act as a Virtual Power Plant. This will include a target of 200 units within the test bed substations, 25 income qualified installations, and 300 units anywhere in the service territory.

Using assumptions from a Tesla Powerwall 2, it would take approximately 570 operational units to meet the minimum desired capacity of 1 MW on the darkest day of the year.[134] However, at the proposed level of 525 units PGE will be able to meet the desired 1 MW of capacity for four hours 80 percent of the year using the same assumptions as above and with historically average weather. The eventual proportion of devices restricted to solar charging (due to receipt of the Federal Solar Investment Tax Credit, or "ITC") will impact the required number of units, as batteries that can grid charge average over double the discharge capacity during Portland's rainy months.

To ensure PGE can test locational value, a concentration of devices will be required to test impacts on the distribution system. For this reason, additional incentives will be provided to customers within the three PGE Test Beds to achieve a measurable effects on a single distribution feeder. A single residential battery system fully charged may deliver 5 kW at any given point in time, which represents about 0.05% of a distribution feeder's typical load. To have a measurable impact on a distribution feeder's performance, concentrations that affect the power flow of at least 3%, or 0.2-0.3 MW of energy storage per distribution feeder, are necessary. Anything less than this impact is lost within the margin of error, and the opportunity to explore location-specific value diminishes. Using the same math as above, to reach 0.3 MW of capacity during the lowest production solar month on a single feeder requires a minimum of 171 batteries. PGE will pursue other methods of inducing density beyond just the Test Bed, including working with new home builders who may want to include battery storage in a subdivision.

PGE will easily stay within the stipulated capital restriction of $1.5M, as there is close to no capital projected for this Pilot, and the Company has designed the Pilot to stay well within the operations and maintenance (O&M) targets set in UM 1856.

A.7.5 Market Trends

In PGE's service territory, there are approximately 150 residential battery installations and about 15,000 rooftop solar installations.[135] PGE's Test Bed currently has 407 rooftop solar installations and three homes with a battery installed.[136] Achieving the targets outlined above will require more than tripling the existing battery installations in PGE's territory within three years. Current market trends support these projections, with the most recent Wood Mackenzie Energy Storage Monitor forecasting a tripling of residential energy storage capacity nationwide from 2020 to 2024, as shown in Figure 32.[137]

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[134] Assuming 100% of usable energy capacity is used for a 4-hour discharge in aggregate, and is optimized for the average production in the lowest solar production month with solar size of 4.87 kW nameplate (the median residential solar installation on our system), then ITC-restricted batteries have 5.4 kWh of usable capacity on an average December day per PV Watts. If 80% of installed batteries are ITC-restricted, with the other 20% being able to charge from the grid (thus having 13.5 kWh of usable capacity), then we need 570 batteries to achieve 1MW discharge for 4 hours. The math goes as follows- Solve for n: (0.2 * 13.5kWh / 4h + 0.8 * 5.4kWh / 4h) * n = 1000kW

[135] PGE (2020)

[136] Id.

[137] Wood Mackenzie P&R/ESA U S energy storage monitor Q 4 2019

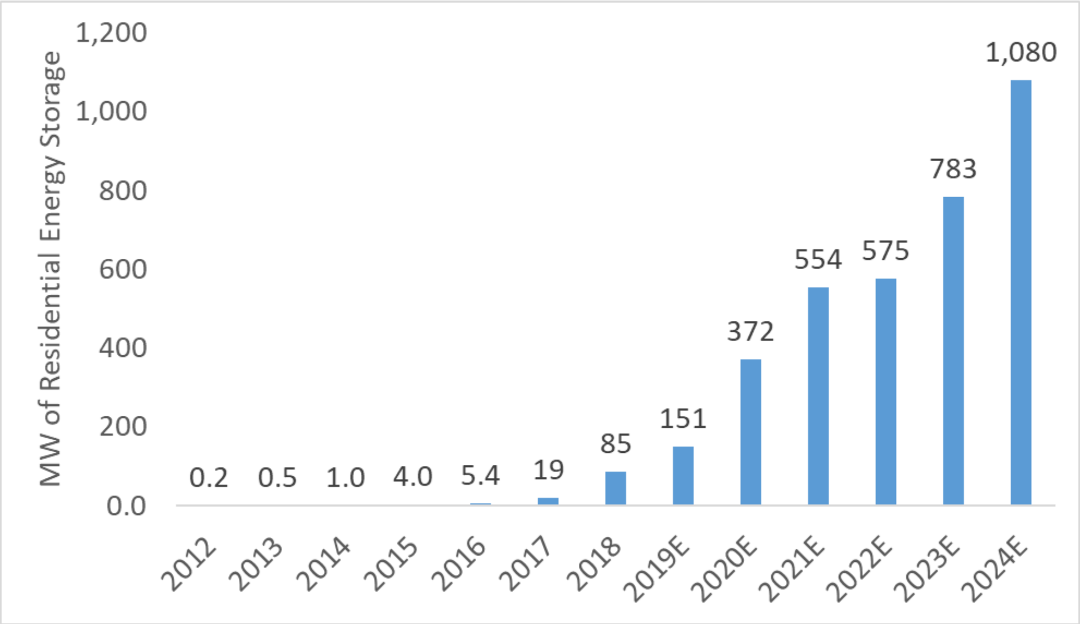

Figure 32 – U.S. Residential Energy Storage Deployment Forecast (MW)

Research by Navigant Consulting that forecasts residential energy storage adoption in PGE's service territory shows similar strong projected growth, with a base case of nearly 700 batteries in PGE's service territory by 2023 and a high case forecast of nearly 2,500 installed batteries, as shown in Figure 33.[138]

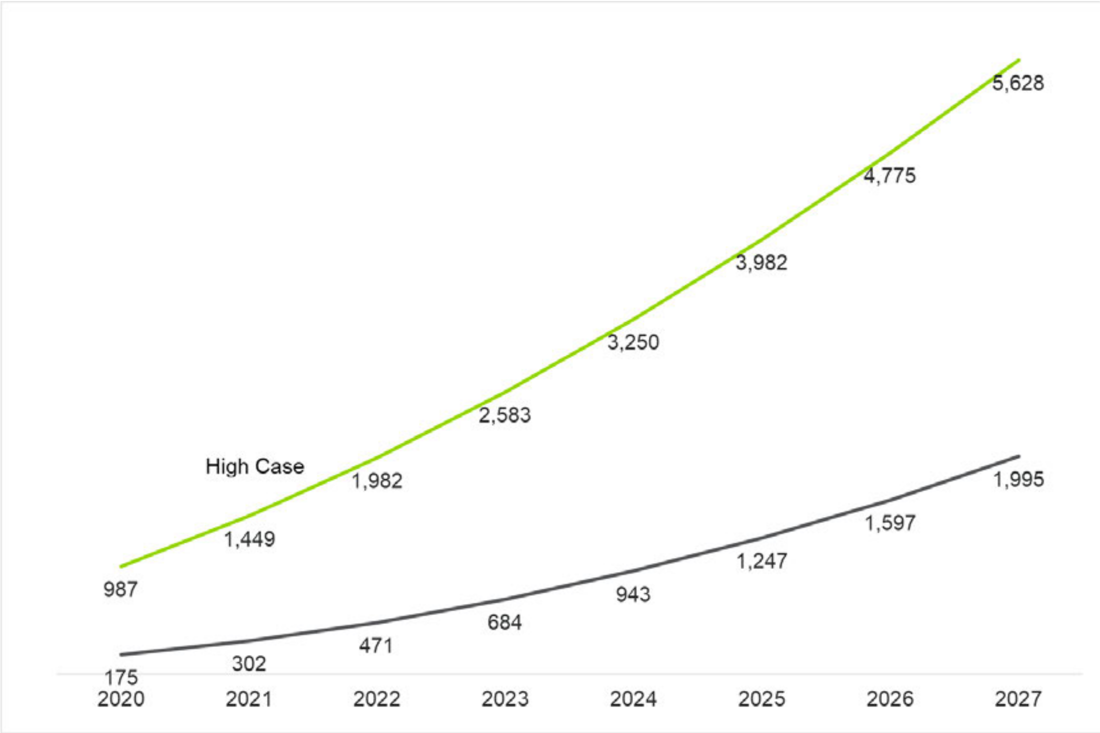

Figure 33 – Navigant Residential Storage Forecasted Installations

One of the drivers of adoption considered by Navigant was the customer's value of resiliency. This may increase due to the public safety power shutoffs in California and extreme weather events in the Northeast and Southeast.

Regarding financial drivers, the Wood Mackenzie report states:

> *In the future, factors including battery price reductions, declining hardware and controls costs, product standardization and process optimization will drive system-level price declines in the residential and non-residential BTM markets. Beyond just component-cost reductions, improvements in soft costs will also be realized as the market attains further maturity and policy changes drive improvements in permitting and interconnection processes.*

Additionally, the continued decline in lithium-ion battery pack prices will aid residential storage adoption. Since 2010, the price of lithium-ion battery packs has declined over 85% from 1,183

[138] Navigant PGE DER Forecast (2019)

$/kWh to 156 $/kWh in 2019[139]. Nationwide, the decline in lithium-ion battery prices resulted in a 500% increase in residential storage from 2017 to 2018. Battery prices are expected to drop below $100/kWh by 2024[140].

These market trends, paired with well-designed incentives and an increased awareness of resiliency among Oregonians, will allow this Pilot to meet its enrollment goals. The Company conducted a market research study in January 2020[141] with 1,432 customers completing the survey. Results showed that almost half (45%) of survey respondents are familiar with battery storage systems, with 63% interested in learning more. Twenty of the 37 customers surveyed who already have a battery system would consider allowing PGE to manage their battery charging and discharging without any mention of an incentive, while three-quarters (76%) of customers without a battery system would hypothetically consider allowing PGE to manage their battery charging and discharging without any mention of an incentive.

A.7.6 *Lessons to be Learned*

The key objective of the Residential Battery Storage Pilot is to collect as much information as possible about the impact of residential battery storage in four categories: The Energy Portfolio, the Grid, the Customer, and the Program.

A.7.6.1 The Grid

The primary goal of the pilot is to evaluate the ability of residential batteries to deliver locational value in support to PGE's electrical system. The grid value questions this pilot seeks to explore are:

- Explore the effectiveness in shaping load, and the potential for distribution upgrade deferrals
- Evaluate and refine setpoints and settings for advanced inverter capabilities to maximize locational value while maintaining local system reliability and retaining battery longevity
- Understand the effectiveness of batteries to support Volt-Var optimization
- Understand the ability of residential batteries to relieve hosting capacity constraints
- Understand the compatibility of stacked services, and the frequency of conflicting dispatch priorities between locational Grid services and Bulk Energy services

A key pilot finding will be the determination of values for each tested use case, including both generation and locational values. Modeling is useful to estimate these values, but this pilot will serve as a field test to assess the accuracy of the modeling and the actual experiences in customers' homes. Accurate valuation must also reflect the batteries' ability to integrate with the markets and dispatch entities relevant to each use case. The pilot will explore all value streams and remains open to any learnings obtained through this project. The specific use cases that PGE will be evaluating are autonomous Volt/Var support, autonomous frequency response, BAO

[139] BNEF (2019)
[140] BNEF (2019)
[141] PGE PV/Battery Survey, 2020

dispatch of contingency reserve, and bulk generation capacity deferral, however PGE will also pursue any additional use cases that arise as technically feasible over the course of the pilot.

PGE will explore the services and attendant values agreed to in Order 17-118, Appendix A[142]. Additionally, PGE will investigate the value of these distributed distribution system-sited resources to the bulk grid. Similarly, PGE will explore distribution system values from operating this fleet of batteries—including both local distribution system value and systemwide generation values.

These grid and operational learnings will be captured through quantitative analysis of the batteries' performance, evaluated internally through the EPRI StorageVet tool and externally through a third-party evaluation consultant. All batteries will be integrated into GenOnSys, which is PGE's control software package currently used for the Dispatchable Standby Generation (DSG) program. GenOnSys will provide PGE and the evaluator with access to all the relevant historical data about inverter charge/discharge times, state of charge, and current and voltage levels. Should PGE opt to not dispatch the batteries through GenOnSys for any reason, data will also be stored by the aggregation platform in the utility portal.

Actual dispatch of the battery will be subject to uncertain grid conditions and limitations in real performance. PGE will evaluate the actual dispatch for the grid benefits provided and will use the results to inform future StorageVET® evaluation and modeling. This feedback loop will refine PGE's ability to make informed, economic, and transparent decisions for future storage-related pilots and programs. The grid value learnings are intended to inform PGE's Integrated Resource Plan (IRP) so that residential battery energy storage can be properly valued, and a cost-effective scalable program may be developed.

A.7.6.2 The Energy Portfolio

The pilot has the potential to stack values relevant to PGE's bulk energy portfolio. The bulk energy value questions this pilot seeks to explore are:

- Evaluate the cumulative number of hours the aggregate residential energy storage resource is dispatched to serve Bulk Energy use cases, and total value accrued for those services
- Test base assumptions around Bulk Energy resources such as load following and primary frequency response
- Determine the accuracy of PGE's modeling inputs to the EPRI StorageVET and its suitability as a planning tool (inform IRP values for use cases)

A.7.6.3 The Customer

The pilot will allow PGE to develop operating protocols that balance the needs of the grid with those of individual customers. It will specifically identify how best to extract the greatest value for PGE's investment without jeopardizing customer participation in the pilot. PGE will evaluate

[142] OPUC UM 1751 Order 17-118 https://apps.puc.state.or.us/orders/2017ords/17-118.pdf

Customer Needs around battery energy storage through a combination of qualitative and quantitative analysis. Topics PGE seeks to explore include:

- Acceptance of PGE control of the battery
- Preference for up-front rebate or ongoing compensation
- Hurdles to battery adoption
- Target market most likely to purchase battery storage
- Messaging that customers relate to for value proposition of utility control
- Identification of gaps between battery performance and customer expectation (especially when it comes to longer-duration outages)
- Balancing use of the battery for grid services with customer reserve in the event of an outage
- Device communication performance, uptime, hurdles
- Frequency of opting-out of dispatch
- Average battery state of charge and availability to provide customer backup
- Average number of cycles per year, and effect on battery degradation
- Customer economics of battery usage, potential of TOU optimization

PGE will do this through:

- Baselining customer surveys of awareness, interest, and consideration testing prior to pilot launch
- A/B testing of messaging and outreach
- Ongoing customer surveys of those who enroll in the pilot on their experiences and satisfaction
- Surveys of those who do not enroll in the pilot (identified as those who install solar panels through the Energy Trust program but do not purchase a battery) to better understand their barriers, and
- Interviews and/or surveys with installers to understand what questions customers are asking, barriers to installation, and ideas they might have for increased adoption.

The pilot will test the willingness of customers to allow PGE to operate their battery in exchange for payment, and whether PGE's proposed payment is sufficient to encourage pilot participation. A key pilot learning will be whether the monthly payment and up-front rebate amounts are appropriate. PGE is employing a tiered, up-front rebate that will start higher and reduce as customers are enrolled—allowing PGE to test the efficacy of various incentive levels on customer uptake. If the pilot struggles to enroll customers, a second phase of the pilot may involve re-working the offers. Conversely, if the pilot reaches capacity faster than anticipated and has a robust waitlist of interested customers, PGE may consider reducing the incentives in any future pilot expansion.

PGE will work to ensure that the financial design is a favorable alternative to bill management. To that end, PGE will evaluate time of use (TOU) rate optimization and general customer economics throughout the pilot. While a battery controlled by the customer and programmed for TOU rates can effectively shift energy load from one time period to another and provide customer bill management, the full spectrum of use cases diminishes without utility operation of the battery.

A.7.6.4 The Program

In addition to learning about customer needs and grid value of battery storage, PGE will utilize the pilot to inform a future recommendation on scalable future program design and the most appropriate business model for PGE in the residential battery storage market. This includes understanding efficiencies that can be achieved through program design, unanticipated costs and hurdles of battery storage implementation, the best practices for aggregated control & dispatch, balancing cost with operations, understanding the full value streams available from batteries so a cost-effective program can be developed, and the ability to strategically select locations for storage to create a program that best utilizes distribution upgrade deferral. Specific questions PGE seeks to address to inform future program design include:

- Study reliability and efficacy of various communications protocols, LTE cellular data vs. Wi-Fi
- Understand cost versus benefits of communications methods
- What is the best way to manage integrations of multiple APIs?
- Determine actual financial impacts on customer bills, appropriate way to utilize non-utility measurement and metering devices
- Quantify actual Round-Trip Efficiency (RTE) losses of interconnected batteries- vendors report efficiencies under “ideal conditions,” how do customer homes compare to ideal conditions, what is the range of field efficiencies that are observed
- Quantify what increased value is available due to direct control/dispatch from the utility versus passive measures to incent customer behaviors (e.g., TOU)
- Set effective incentive levels to develop a cost-effective scalable program
- Tolerable use cases and battery usage for customer acceptance

While the default option for battery storage communications will be customer-hosted internet (Wi-Fi or ethernet), some (though not all) of the batteries on the qualified products list (QPL) have LTE capability that can be activated. PGE will track the effectiveness and availability of customer hosted internet and has selected an aggregation platform with multi-modal messaging to customers whose batteries go offline to remind them to reconnect their device to the internet if they wish to remain in PGE’s pilot. PGE may opt to offer LTE cellular communications to income qualified participants and other customers who are deemed to have insufficient internet coverage and will evaluate the costs versus benefits of utilizing customer internet versus PGE hosted LTE cellular data.

A.7.6.4.1 Development of Integration Best Practices

A key research objective is the development of best practices for integrating distributed resources into existing asset control systems, and to measure the acceptance of battery storage systems as a tool for renewable power integration. In PGE's Proposal and in the Stipulation approved in Commission Order No. 18-290, PGE committed to aggregate and dispatch residential energy storage as a fleet. Aggregated dispatch will allow PGE to evaluate battery impact on generation services and transmission & distribution (T&D) services,[143] while also allowing the resources to be used by PGE Power Operations for generation capacity, energy resource optimization, and contingency reserves.

A.7.6.5 Generation Services

The intent of dispatching the residential energy storage devices as a fleet is to evaluate each of the potential use cases which include bulk energy and ancillary services. PGE intends to also collect learnings for localized T&D grid services, which can respond to localized controls/settings or a coordinated dispatch at the feeder/substation level. These values can be co-optimized to enhance the total potential value represented by a residential energy storage device, but only to the degree that the resource is of sufficient size to participate in delivering Bulk Energy and Ancillary Services or Distribution Capacity Deferral (PGE Power Operations dispatches in 1 MW increments). If aggregated and dispatched as a Virtual Power Plant of 1 MW or larger, PGE will gain learnings in co-optimizing the Bulk Energy and Ancillary Services along with the localized T&D services.

A.7.6.6 T&D Services

In aggregate, fleet operation should be significant enough for grid operations to see the effects of the resource as it moves from the grid edge to distribution operations to the bulk system. Once PGE understands how best to design a controls hierarchy which co-optimizes the aggregate resource while retaining appropriate localized value for individual units, the Company will be better positioned to further incorporate residential programs into T&D planning. This represents a major learning for PGE which can also inform our efforts to value and effectively integrate other distributed energy resources (DERs) into T&D grid planning and operations.

PGE will test location-specific functions like the ability to manage distribution feeder voltage, or the ability to reliably influence distribution power flow. In understanding how reliably these devices can deliver these services, and how much impact they are able to have on the distribution system, it will help calculate what theoretical locational value may exist. PGE may then establish settings for the devices to operate based on location-specific needs while also co-optimizing grid services around them and learn to what degree those services conflict with each other or are compatible with each other. Finally, PGE will compare performance for direct-control over the storage assets versus what we anticipate performance to look like for passive-control (e.g., Time of Use) to determine which is more cost effective.

A.7.7 *Managing Costs and Cost Effectiveness*

Pilot capital costs fall within the stipulated maximum of $1.5M overnight capital. The only portion of the Pilot that qualifies as a capital expense at this time is the purchase of test batteries that will

[143] See page 5 of Commission Order 18-290 in Docket UM 1856

be installed in PGE locations for training and dispatch testing purposes at an estimated cost of $33,000 (five-year NPV of $40,000).

The O&M costs outlined below are the costs that PGE will include in its deferral request. Per the stipulation of UM 1856[144], evaluation costs are not included in this budget. The costs specific to operating this residential pilot will be included as part of the deferral, though in accordance with the stipulation no administrative costs of operating the entire portfolio of battery storage projects are requested.

PGE will stay within the guidelines of $5.7M NPV of revenue requirement and a year one revenue requirement of $700k. O&M costs are comprised of incentives (monthly + Test Bed and income qualified upfront rebates), program operations (Energy Trust contract, PGE program management, customer outreach), and the cost to dispatch the batteries as a fleet.

The table below reports pilot costs on a Net Present Value basis over the five-year pilot life. This is the amount (excluding the capital costs) that will be requested in the deferral application.

Table 20 – Pilot Budget: five-year NPV, 2020$

Budget Item	Rounded ,000
Incentives	$1,290
Monthly incentives; Grid Charging	$547
Monthly incentives; PV Restricted	$272
Test Bed Rebates	$362
Income Qualified Rebates	$109
Pilot costs	$926
PGE Program Manager	$376
PGE Customer Outreach	$61
ETO implementation	$423
Energy losses	$66
Aggregation & Dispatch	$604
Aggregation platform	$354
GenOnSys API Integration	$88
Vendor communications fee	$162
Total Requested Deferral	$2,820
UM 1856 O&M Budget	$5,700
Capital costs to utility	$40
Test batteries	$40
UM 1856 Capital Budget	$1,500
Total Budget	$2,860

[144] UM 1856 Partial Stipulation

A.7.8 *Cost Effectiveness*

The activity in the residential battery demonstration project is not cost effective. The primary objective is to learn as much as possible in a small-scale R&D type pilot to understand the appropriate pathway to cost-effectiveness, and to inform IRP values that will be required to appropriately quantify the benefits for a future cost-effective battery storage program. PGE has worked hard to limit the total spend and thus the cost risk to which ratepayer, the utility and participants are exposed. One of the primary reasons the project does not include an option for PGE to own the batteries is because the costs were simply too high and primary lessons to be learned could be acquired at less cost through the approached filed with the Commission March 12, 2020.

A.7.9 *Evaluation*

Under the stipulation in Order 18-290, PGE must file an annual compliance evaluation report and comprehensive evaluations in years 3, 6, and 10 of the pilot—looking at all five of the battery pilots approved under the order. PGE proposes to file a comprehensive evaluation in year 3 after the recruiting phase is complete, and the final evaluation in year 6, after the pilot is complete. Table 21 outlines the evaluation schedule.

Table 21 – Evaluation Schedule

Year	Activity	EOY Projected Capacity
1	Pilot Launch	175 customers, between 0.2MW-0.6MW for 4 hours
	Year 1 Recruitment Activities	
	Compliance Evaluation Report	
2	Year 2 Recruitment Activities	350 customers, between 0.4MW-0.2MW for 4 hours
	Compliance Evaluation Report	
3	Final Year of Recruitment	Full subscription: 525 customers, between 0.57MW-1.77MW for 4 hours
	Comprehensive Mid-Pilot Evaluation	
4	Recruitment closed, pilot operations	
	Compliance Evaluation Report	
5	Final Year of pilot Operations	
	Comprehensive Final-Pilot Evaluation	

A.7.9.1 *Comprehensive Reports*

The comprehensive mid-pilot and final evaluation reports will be completed by a third-party, and PGE will issue a competitive request for proposal (RFP). The evaluation should conform with established industry standards (e.g., the Department of Energy's Protocol for Uniformly Measuring and Expressing the Performance of Energy Storage)[145]. This protocol outlines how to perform baseline and duty cycle tests to ensure a battery storage system can perform at the required response times for various grid services. PGE will require selected evaluators to note and justify any deviations from this protocol.

[145] https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=8274603

PGE will use GenOnSys to integrate all the batteries. GenOnSys as well as the aggregation platform will capture and provide historical access to all the relevant data about inverter charge/discharge times, state of charge, and current and voltage levels.

The comprehensive reports will seek to answer the questions laid out in the “Lessons to be Learned” section, and to quantify the IRP values of any tested use cases that PGE was able to execute.

More details on the evaluation plan are available in PGE’s January 25, 2019 Addendum filed in UM 1856[146]

A.7.9.2 Annual Compliance Reports

Between comprehensive filings PGE will complete annual compliance filings. Compliance evaluation reports will be prepared by internal PGE resources, and will include qualitative and quantitative updates on pilot’s progress, including:

- Participation metrics – customers recruited, enrolled, who have dropped out, etc.
- Demographic profile of participating customers
- Budget update – projected and actual spend
- Available capacity
- Any in-house modeling results that have been conducted
- Any in-house calculations on RTE losses, actual TOU billing impacts
- Integration and dispatch methods, what’s going well and what needs improvement
- Communications metrics – Wi-Fi uptime, LTE metrics, lessons learned
- Results of any customer and/or installer surveys and/or interviews

Below is a table of the detailed learnings that PGE committed to studying through this pilot in its compliance filing, along with the learnings hoped to gain and the method for achieving the learning.

[146] UM 1856, Addendum to PGE’s Residential Storage Pilot, filed Jan. 25, 2019, at 16-18, https://edocs.puc.state.or.us/efdocs/HAD/um1856had123254.pdf.

Table 22 – Evaluation Risk Management Plan

Risks	Learnings	Method
Risks of Personal Injury and Property Damage	Document issues in installation, maintenance, and decommissioning of units, as well as resolution strategy.	Internal project tracking; stakeholder interviews
Risk of Power Quality or Reliability Impacts	Capture incidence and trajectory of issues to inform PGE on what to expect from systems in the field and understand what level of support needed to ensure power quality is appropriately maintained.	Data historian for management system (GenOnSys) made available to evaluator
Integration Risk	Can be both infrastructural barriers and software integration issues: • (Power systems side) PGE will continue to develop expertise in performing hosting capacity assessments as-needed to support pilot deployment. • (Communications) PGE will monitor communications uptime through its management platform • (Software) What kind of integrations are required between management system at customer site and central control system? In the course of sustained operations, what are the relative firmware upgrades or updates to relevant APIs? • PGE will gain applicable learnings around smart inverter settings for customer-connected devices and how these can affect hosting capacity.	• (Hosting capacity): captured in project documentation and stakeholder interviews. • Communications downtime monitored through PGE's management platform and recorded in data historian. • Software integration issues documented as necessary.
Risk of Inopportune Timing	How does deployment timeline relate to customer and/or system needs, and what are the implications if exogenous drivers occur during the pilot timeframe? (E.g., additional rebates or community initiatives, or large concentrations through new construction).	PGE will monitor these events and document in the process evaluation.
Risk of Low/High Enrollment	Need a representative sample to the extent possible to ensure enough diversity of load profiles to understand various use cases. In addition, PGE is interested in determining what tools are effective (or not) at marketing energy storage to residential customers? How does the ownership model affect participation, decision making to enroll, and satisfaction?	Process evaluation will review marketing materials, benchmark similar programs, conduct stakeholder interviews, and include customer surveys.
Risk of Partner Failure	By requiring adherence to open communications protocols, PGE hopes to mitigate risk due to vendor changeout in a quickly evolving market. PGE will assess performance of hardware, software, aggregations, and O&M vendors contracted through the pilot.	Conduct post-failure analysis to understand cause of failure (for cases when vendors fail to perform duties). Also through stakeholder interviews with key program staff at PGE and with implementation partners.
Risk of Supply Chain Failure	PGE will seek to engage early with vendors to plan deployment and secure delivery guarantees. PGE will pursue alternate vendors as appropriate if supply chain problems exist. Learnings will inform program planning assumptions for future offerings.	Reasons for delays will be recorded and mitigated where possible. Stakeholder interviews will capture issues and recommend strategies for mitigation on wider rollout.

A.7.10 Moving from Pilot to Program

The purpose of the Residential Battery Pilot is to learn how to control a geographically diverse, distributed energy resourced situated behind the meter for various co-optimized energy services. The resource as it will be dispatch in the aggregate so that power operations can control and extract services will meet at least one important program factor, Dispatch Integration. However, because the residential battery effort is very new PGE at present needs to explore the other factors before being able to communicate with confidence the pathway of the effort to a formal program. For example, one of the primary learnings to be explored in the Residential Battery Project is to better understand infrastructure stability of behind the meter residential batteries. PGE will keep the Commission updated through regular check-ins as proposed in the planning chapter of this document.

A.7.11 Pathway to Flexible Load

Behind the meter batteries are the ultimate flexible load capable of provide a host of co-optimized grid services. Through this project we will explore how flexible and how well the resource can be leveraged by the PGE system for flexible load services.

A.7.12 Activity within the Testbed

Customers living within one of the PGE Test Beds[147] are eligible for an up-front rebate in addition to the monthly bill credit. This is to encourage density on the three select substations of the Test Bed and to allow PGE to study locational T&D impacts. To encourage prompt action as well as to test the impact of varying incentive levels on uptake, PGE will employ a tiered incentive that steps down after a certain level of uptake. Among the targeted 200 Test Bed participants, the first third will receive $3,000, the second third will receive $2,000, and the last third to enroll in the pilot will receive $1,000.

Customers receiving the up-front rebate will sign an agreement to participate in the entire pilot, or PGE has the option to require re-payment of the unamortized portion[148] of the rebate.

To ensure PGE can test locational value, a concentration of devices will be required to recognize impact on the distribution system. A single residential battery system fully charged may deliver 5 kW at any given point in time, which represents about 0.05% of a distribution feeder's typical load. To have a measurable impact on a distribution feeder's performance, concentrations that affect the power flow of at least 3%, or 0.2-0.3 MW of energy storage per distribution feeder, are necessary. Anything less than this impact is lost within the margin of error, and the opportunity to explore location-specific value diminishes. To reach 0.3 MW of capacity during the lowest production solar month on a single feeder requires a minimum of 171 batteries. PGE will pursue other methods of inducing density beyond just the Test Bed, including working with new home builders who may want to include battery storage in a subdivision.

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[147] As defined by PGE Rate Schedule 13.

[148] This is calculated as the proportion of the unpaid amount when calculated over the potential length of time the customer would have been eligible to participate in the Pilot.

A.8 Single Family Water Heater Testbed Demonstration

A.8.1 Description

PGE is leveraging R&D funding to perform a demonstration project for interconnecting single-family water heaters for demand response, and specifically heat pump water heaters. The objective of the research is to test varied communications protocols beyond customer hosted Wi-Fi, assess the demand response potential of heat pump water heaters, test incentive mechanisms, and better understand the options for a future scalable cost-effective single-family water heater program.

The communications protocols PGE seeks to employ for this demonstration are customer-hosted Wi-Fi, cellular LTE, and a mesh radio frequency network. The customer hosted Wi-Fi will use water heaters with onboard Wi-Fi chips for a "bring your own appliance" method of enrollment, while the LTE and mesh network controls will rely on water heaters with CTA-2045 capabilities and will be a much higher touch effort. The goal is to enroll 150 water heaters, 50 for each communication protocol. The demonstration may target existing homes as well as new construction single family homes.

An incentive may be provided to customers who enroll in the demonstration, as well as an ongoing incentive for continued participation. Builders in new construction may receive the enrollment incentive and potentially some or all of the ongoing incentive for purchasing a compliant heat pump water heater and enrolling the device in the demand response program.

The single-family water heater demonstration project will differ from the multifamily water heater pilot in an important distinction. PGE is committed to energy efficiency as the first fuel. To this end, it is important that where possible PGE flexible load resource building endeavors not complete with energy efficiency procurement. Thus, the single-family water heater demonstration will be working to connect heat pump water heaters, the most efficient electric water heat option. This is also why the endeavor is demonstration within the Testbed. PGE needs to explore the capabilities of these units to provide load shed.

A.8.2 Learnings

Enabling water heaters for DR purposes in single family settings has not historically been cost-effective for a few primary reasons.

Historically water heaters have been demand response enabled by having a licensed contractor install an intelligent switch on a water heater's control panel. In a multi-family scenario economies of scale can be achieved with regards to installation labor, but having contractors spend time travelling between installation sites for specific installation windows with specific customers at least doubles the installation costs. This pilot will test newer technologies that don't require a licensed contractor.

The cost to enable a water heater with communications devices independent of the customer's own Wi-Fi has been prohibitive in the past. PGE has found that an alternative communications protocol to Wi-Fi is preferred due to disconnects from router reboots, energy outages, etc. This study will evaluate the costs of alternatives versus the benefits of improved reliability. Cellular

LTE data costs have been declining and may be approaching a cost that is appropriate for dispersed water heater controls. A mesh network operating radio frequency does not have ongoing costs to operate, but PGE must understand the cost and complexity of erecting a network and understand the limitations to reaching devices that may be located in customer basements or other out of the way locations. And finally, while PGE has historically found that customer Wi-Fi is unreliable for appliance controls, will the emergence of the “internet of things” and increasingly connected lifestyles improve that reliability? Can incentive design paired with prevalent appliance apps encourage customers to re-connect a device that has fallen offline? Understanding these questions will enable PGE to move forward with a cost-effective and scalable program for the future.

A.8.3 Single Family Water Heaters as Part of PGE Decarbonization Strategy

Single family water heaters are is a top priority for PGE’s decarbonization strategy as water heating is typically the second largest energy use in a home, only behind space heating. Testing in the multifamily water heater pilot shows that most customers do not notice when their water heater is being controlled by the utility for grid services, and thus demand response activities and grid services can be performed much more frequently than other events that may require more customer involvement or potential discomfort for customers. Additionally, water heaters, like batteries, are able to store and release energy. While the energy cannot be released back on to the grid like batteries, water heaters do demonstrate the ability to take service from the grid in sub-hour and possibly sub-fifteen minute increments.

A.8.4 Goals

The goals of the demonstration pilot are to:

- Understand the costs and benefits of various communications protocols for demand response of single-family water heaters
- Quantify the potential value of demand response in heat pump water heaters
- Understand the complexities, costs, and efficacy of a mesh network using radio frequency communications
- Pilot the use of CTA 2045 communications technology with customers

A.8.5 Roadmap to a Scalable Program

By gathering the learnings outlined above, in conjunction with the experience of the multifamily water heater demand response pilot, PGE will develop a cost-effective and scalable program that correctly values the incentive structure for customers, utilities cost-effective communications protocols and dispatch strategy, and employs a streamlined interconnection strategy.

PGE and the Energy Trust will collaborate to explore a joint incentive structure for heat pump water heaters supporting this key technology. Because heat pumps are so highly efficient they have a lower potential for demand response, and collaboration with energy efficiency partners is required to send proper market signals to customers and pursue a cost-effective program.

Through incentive data collected by PGE, Energy Trust, and the state of Oregon from the RETC, PGE is able to identify homes with the specific models of heat pump water heaters that are able to be interconnected into a demand response program. Until a code requirement is in place that mandates all water heaters have demand response capabilities PGE will perform targeted outreach to customers for existing appliances, and work with installers and home builders to incent the installation of new water heaters with DR capabilities.

Customers surveys and focus groups consistently convey that customers want to participate in clean and advanced energy programs that provide an environmental benefit and are eager to participate in programs that have either non-existent or relatively low up-front costs for participation. PGE plans to provide this program at no cost to participating customers and may provide a one-time enrollment incentive as well as performance / participation incentives, dependent on the costs to operate the program and the value streams that emerge.

The ultimate goal of the pilot is to identify a path to a cost-effective demand response program for a multitude of single-family water heaters, including both electric resistance and heat pump. Electric resistance water heaters comprise a significant proportion of water heaters within the single-family housing market and have high levels of demand response capacity, however, are more difficult to interconnect. Heat pump water heaters are increasingly being sold with demand response capabilities built-in, and pair with energy efficiency goals.

The target market for single family housing with electric water heating is estimated to encompass 148K households, with an achievable potential of 74,000 households that represents 37 MW (assuming a capacity of 0.5 KW per water heater). Successfully establishing both the Single-Family Water Heater program and the CTA2045 standard may allow for water heaters to be DR-enabled by code by 2025.

A.9 Residential Smart Charging Pilot

A.9.1 Program Description

In March 2020 PGE proposed a Residential EV Charging pilot ("Pilot") to encourage customers to deploy connected Level 2 EV Charging (L2) infrastructure at their homes. The program, which targets single family homes, aims to provide rebates for approximately 3,600 charging stations over a three-year period. Participants will receive a rebate ranging from $500-1,000 per charger, and EV dealers will receive a $100 mid-stream rebate for referring a qualified successful EV charger installation. Further, the pilot will test the effectiveness of providing grid services, specifically demand response (DR) using home chargers, by offering customers a $50 annual incentive for participating in grid services events.

A.9.2 Program as part of Decarbonization

The program will support Oregon's climate goals, accelerate TE, and encourage efficient grid integration by:

- Reducing customer costs: Decrease costs associated with deploying charging infrastructure at home and at businesses;
- Enhancing customer experience: Simplify and standardize the EV charger buying and installation process;
- Enabling efficient grid integration: Ensure that future charging stations deployed in PGE's service territory are connected and participating or have the ability to participate in smart charging programs; and
- Supporting greater EV adoption in moderate-income and low-income communities: By offering larger incentives for qualifying individuals and facilities and by supporting transit agencies in electrifying their fleets.

A program like this one is likely to help accelerate Oregon's transition to a clean energy future. The proposed pilot wholly supports the state's goals to decarbonize the transportation sector while ensuring that we are building a grid that can maximize value from these new distributed energy resources (DERs). As our customers' trusted energy partner, PGE brings a balance of technical knowledge and customer acumen to deliver programs to accelerate TE and create value to the grid. We believe that this pilot will make charging more affordable, simplify the experience around installing charging infrastructure, increase the number of charging points in PGE's service territory, and create a pathway to capture and quantify new flexible energy resources.

A.9.3 Goals

PGE proposes to launch a Residential EV Charging pilot to encourage customers to deploy connected L2 infrastructure at their homes. The pilot targets single-family homes and aims to provide rebates for approximately 3,600 charging stations over approximately a three-year period. The Residential EV Charging pilot aims to:

- Encourage EV adoption by reducing the cost and complexity of installing qualified connected charging stations; and

- Explore and establish mechanisms to realize the value of the delivery of grid services (DR, daily load shifting, and load following) from connected chargers.

Table 23 – Residential Smart Charging Pilot Structure

Incentive	Projected Participation
Standard EV charger installation incentives	3,250 incentivized installations
Income-eligible EV charger installation incentives	360 incentivized installations
Grid Services	2,800 participating EV chargers

A.9.4 Market Potential

Through customer interviews, PGE found that EV buyers exhibit several key needs and wants. Many customers don't know how to navigate the transition from gas-fueled vehicles to EVs. While customers want green affordable transportation[149], they struggle to quantify the benefit of EVs when considering the purchase of a vehicle.

Customers want charging that is fast, easy, and convenient enough to compete with traditional fuel. The pilot is designed to address the fact that most homes do not have an available 220 volt / 30-40 amp circuit installed in their garage or driveway to accommodate a L2 charger.

EV chargers represent an incremental cost[150] for EV buyers to move from fossil fuels to electric. Financing of charger and installation costs are often not addressed by EV manufacturers or dealers during the EV sales process. As a result, customers face many home charging options and often choose the lowest cost option, which is often not connected and has no opportunity for grid integration.

Many customers simply lack the information they need to figure out that EVs are affordable, reliable, and can make financial sense for them. Finally, early EV adopters and potential EV buyers indicate that they desire to be perceived as smart and knowledgeable within their community (e.g. friends, family, co-workers) when transitioning from gas-powered vehicles to EVs.

Through customer interviews, PGE found that typical buyers of EVs fall into the annual household income category of greater than $60,000. Despite this, PGE found that all the buying groups desire to drive green, eliminate the use of fossil fuel to meet their transportation needs, and are

[149] Edmonds, Ellen. (2018, May 8). *1-in-5 U.S Drivers Want an Electric Vehicle*. AAA. Retrieved from https://newsroom.aaa.com/2018/05/1-in-5-us-drivers-want-electric-vehicle/
[150] Agenbroad, Josh (2014, April). *Pulling Back the Veil on EV Charging Station Costs*. Rocky Mountain Power Institute. Retrieved from https://rmi.org/pulling-back-veil-ev-charging-station-costs/

generally supportive of and/or are existing participants in PGE green programs (e. g. renewable power, DR, paperless billing).

The market size of potential EV adopters (innovators through early majority) in PGE's service territory is estimated at 240,000 households. Roughly 30% of these prospective customers are not able to install a home charger because they live in non-owner-occupied housing or have a physical/legal barrier to installing an off-street charger. This leads to a potential target market size of 160,000 installed home chargers (participating households).

The Residential EV Charging program addresses the need for convenient and fast home charging for the 100,000 electric passenger vehicles that are expected to be registered in Oregon by the end of 2025. PGE recently conducted a DER Potential Study[151] through the Integrated Resource Plan (IRP) process, which suggests that Battery Electric Vehicle[152] sales will reach a velocity of 10,600 new registrations per year in PGE service territory in 2025.

As shown in Table 24, research data suggests annual EV sales will accelerate from 1,900 cars per year to 5,500 cars per year during the timeframe that we propose for this pilot. The cumulative number of EVs sold in the period from 2019-2022 are estimated at 15,000.

To forecast program participation, PGE estimates approximately 15,000 new EV sales in our service area by 2022[153]. Adjusting for 1) fleet sales, 2) non-qualifying new installations of EV chargers, and 3) customers that do not have the option to install an EV home charger (among other factors), PGE estimates that 6,300 qualifying EV home chargers will be installed during the approximately three-year term of the pilot (see Table 24 for details).

PGE expects that some of these EV chargers, despite being the correct model, will not receive incentives for the installation of the equipment and/or participation in DR events due to lack of awareness for the pilot and/or non-timely submission of incentive applications, among other factors.

[151] Navigant (2019). DER Potential Study.
[152] The estimate does not include registrations of plug-in hybrid electric vehicles (PHEVs) in PGE's service territory. PHEVs have lower battery capacities than BEVs. BEV owners are also less likely to install L2 home chargers.
[153] The forecast model uses high-level macroeconomic factors like gross domestic product and population as well as vehicle density and historic sales data to project overall light duty vehicle market growth. These forecasts are helpful for sizing program adoption but are not intended to suggest that there is not a need to accelerate TE. There is a need to accelerate TE as the forecasted levels of EV adoption are not on pace to meet the Governor's 50,000 EV goal by 2020, nor are they sufficient to meet the state's greenhouse gas reduction goals. PGE expects that programs like this one will add to the customers' value proposition when considering an EV and, in turn, will accelerate transportation electrification.

Table 24 – Estimated Annual EV Sales and Installations of Eligible EV Home Chargers in PGE's Service Territory

Sales by Year	2019	2020	2021	2022	Total	2025
Annual New EV Sales[154]	1,937	3,537	4,296	5,461	15,231	10,613
Annual Installations of Qualifying Charging Stations	700	1,350	1,800	2,500	6,300	NA

Adjusting for fleet sales, non-qualifying new installations of EV chargers, and customers that do not have the option to install an EV home charger (among other factors) PGE estimates 6,300 qualifying EV home chargers will be installed during the approximately three-year pilot period.

PGE expects that some of these EV chargers, despite being the correct model, will not receive incentives for the installation of the equipment and/or participation in DR events due to lack of awareness for the pilot and/or non-timely submission of incentive applications, among other factors.

A.9.5 Lessons Learned

The program will undergo an evaluation to measure the effectiveness of the approach in meeting its objectives, areas for continuous improvements, and energy impacts on PGE's system. The following are some of the high-level learning objectives:

- Track customer participation and satisfaction levels with pilot offerings (grid service events, rebates, dealership assistance, and referrals);
- Understand the level of PGE's influence in customers' decisions to procure an EV and install charging;
- Document charging installation successes and challenges;
- Document and understand the successes and challenges of managed charging for PGE and customers;
- Measure customer load impacts on PGE's system; and

Identify pilot implementation successes and challenges, and improvement opportunities.

A.9.6 Managing Cost and Cost Effectiveness

PGE estimated that the residential and nonresidential customer pilots will have a 14-year net present value (NPV) net cost of $2.4M (which includes $34.7M in benefits and $37.1M in costs).

154 Ibid.

The table below describes the incentives that the pilot will offer to facilitate the above aims.

Table 25 – Residential Smart Charging Pilot Incentives

Incentive Type	Amount	Frequency	Description
Standard Installation Incentive	$500	One-time	For the installation of a qualified connected L2 EV charging station at a single family residential home.
Income-Eligible Installation Incentive	$1,000	One-time	For qualifying income-eligible households, towards the installation of a qualified connected L2 EV charging station at a single family residential home.
Grid Services Incentive	$50	Annual	For customers that are participating in grid services (initially DR, later daily load shifting, and later load following) via the connected charging stations and/or connected vehicle.
Re-Connection and Grid Services Enrollment Incentive	$25-50	Promotional One-time	To encourage enrolled customers whose chargers have lost Wi-Fi connectivity[155] to reconnect their charger. Available at PGE's discretion. For customers with an existing charger who have not received an installation incentive and are enrolling into grid services.

[155] If Wi-Fi connectivity drops below necessary thresholds, PGE will offer this incentive as needed to ensure the operationalization and evaluation of grid services.

Table 26 shows the benefits and costs of the total pilot which includes charger installation rebate and grid services rebate. The combined benefit/cost ratio (rebate + grid services components) of the Residential EV Charging pilot is 0.95.

Table 26 – Blended Cost/Benefit Ratio Based on Combined Pilot Components (Residential EV Charging)

RIM Summary – NPV ($000's)	EV	DR	Total	%
Market Participation Revenue	-	-	-	-
Avoided Cost of Supply	-	1,210	1,210	10%
Revenue Gain from Increased Sales	10,434	-	10,434	90%
Benefits	**10,434**	**1,210**	**11,645**	**100%**
Administrative Costs	2,636	1,530	4,167	34%
Capital Costs to Utility	704	-	704	6%
Incentives Paid	2,276	920	3,196	26%
Increased Supply Costs	4,251	-	4,251	35%
Costs	**9,868**	**2,450**	**12,318**	**100%**
Benefit/Cost Ratio	**1.06**	**0.49**	**0.95**	

The pilot is designed to be in the field for approximately three years. Each charger is assumed to have a life of 10 years. The total pilot period stops 10 years after the last charger has been installed. While the initial number of participating chargers is increasing during the installation period (three years) the number of chargers participating in the pilot is assumed to drop over time. Participation levels drop due to customers moving-in and moving-out out, the charger losing its Wi-Fi connectivity, and other reasons.

A.9.7 Evaluation

PGE expects to submit evaluation findings in an interim report to the OPUC after the winter season spanning 2020 and a final report to the OPUC in the spring of 2023.

A.9.8 Pathway to Flexible Load

The Residential EV Charging program is a flexible load program. As PGE demonstrated in its Transportation Electrification Plan and again the Residential EV Charging Program proposal Time of Use charging is valuable, but a demand response component is needed to address grid constraints, local gird integrity and the ability to manage EV charging load directly. This comports with the criteria found in SB 1547, Section 20 where any program be expected to improve grid efficiency and operational flexibility including renewable integration. The Residential EV Charging Program is structured to address this criteria by the fact that PGE will work to enable new chargers to provide grid services such as DR, load shifting, and load following. These tools will support the integration of renewables on the grid.

A.9.9 Activity in the Testbed

The Residential EV Charging Program will be offered in the Testbed at the same time as the program is offered in the remainder of the service territory.

A.10 Fleet Electric Vehicle - Charging Program

A.10.1 Program Description

PGE is working to develop a program for public (transit, municipal and school bus) and private fleets to minimize the cost and complexity of fleet electrification by offering services that may include fleet planning (vehicle and charging infrastructure) and a turnkey approach to charging, where PGE builds, owns and maintains infrastructure in support of electric fueling. PGE envisions enabling this through modification to our existing line extensions policies. The charging equipment would be grid enabled, meaning it could participate in flexible load grid events (such as demand response). It is anticipated Energy Partner schedule 26 will be adjusted to dispatch these loads over time. Another service being considered is transacting Clean Fuels Credits on a customer's behalf for an administrative fee and crediting the proceeds to participants.

Fleet and transit operators are interested in electrifying their fleets to be more sustainable, and over time lower their operating costs. The vehicle and charging decision are made simultaneously and fueling companies often provide all fueling infrastructure (i.e. own, operate and maintain the fueling source). These businesses need a solution customized to meet their needs. Installing charging infrastructure is time consuming, expensive (especially capacity upgrades) and complex, and is a key barrier to fleet electrification[156]. Customers often want to focus on vehicles, where they have more knowledge, and they find charging presents a steep learning curve.

A.10.2 Program as part of Decarbonization

The program will support Oregon's climate goals, accelerate TE, and encourage efficient grid integration by:

- Reducing customer costs: Decrease costs associated with deploying charging infrastructure;
- Enhancing customer experience: Simplify EV charger implementation and operations
- Enabling efficient grid integration: Ensure that future charging stations deployed in PGE's service territory are connected and participating or have the ability to participate in smart charging programs; and
- Accelerating fleet electrification: By providing tools to support fleet electrification efforts and reducing the cost and complexity of deploying EV charging infrastructure, which is critical to the operation of EVs.

A.10.3 Activity in the Testbed

This program would be offered in the Testbed at the same time as the program is offered in the remainder of the service territory.

[156] Mortenson.2019. EV Industry Trends. 48% of fleet owners ranked charging infrastructure as the biggest barrier to EV adoption. 55% of fleet owners anticipate lead time for charging infrastructure is 1 year or more. 16% of fleet owners ranked financing as the biggest barrier to EV adoption. 46% of fleet owners say substantially more incentives are needed to stimulate widespread adoption.

A.11 Business EV Charging

A.11.1 Program Description

PGE is working to develop a program for business customers to reduce the cost and complexity of installing Level 2 EV charging stations. PGE plans to build, own and maintain the infrastructure up to the parking space, and offer a rebate for the customer's purchase of a qualified charger. An enhanced line extension allowance is envisioned, covering most (or all) of the cost of the distribution system upgrades and the make-ready infrastructure; any costs above the allowance will be paid by the customer.

A.11.2 Program as part of Decarbonization

The program will allow PGE to invest in our customers to decarbonize the transportation sector. Planful investments in EV charging infrastructure will support market growth and charging control, which will enable flexible loads that will be needed in a high-renewables future.

A.11.3 Market Potential

From 2021 through 2023, PGE anticipates engaging ~200 customer sites in the program, for a total of ~1000 charging ports.

A.11.4 Lessons Learned

PGE has leveraged numerous lessons learned from the Electric Avenue expansion and TriMet pilots to understand financial and operational needs to support this type of offering for customers. Ongoing lessons learned will be integrated to strengthen the offering for customers, as well as inform future programs.

A.11.5 Managing Cost and Cost-Effectiveness

Costs for the rebate portion of the offering will be limited to $1 million. Costs for the make-ready portion of the offering will be accounted for using PGE's typical line extension process.

A.11.6 Evaluation

Evaluation will measure the effectiveness of the offering in meeting its objectives and identify areas for enhancement. PGE may measure the energy impacts on PGE's system as part of additional research with separate funding. Learning objectives include, but are not limited to:

- Track customer participation and satisfaction levels with offering (e.g. value proposition, rebates, equipment choices, process);
- Understand PGE's ability to influence customers' decisions to install charging equipment and/or (as appropriate) operate EV fleets;
- Document charging installation successes and challenges, and customers' perceptions of working with PGE; and
- Identify pilot implementation successes and challenges, and improvement opportunities.

Expected process evaluation activities include:

- Logic model

- Data analytics
- PGE administrator interviews
- Participant web surveys
- Attribution analysis (for future program design purposes only)

A.11.7 Pathway to Flexible Load

Participation in demand response will not be a requirement of the offering; however, all chargers deployed through the program will be DR-enabled. A demand response component may be developed and offered to participants in future years.

A.11.8 Activity in the Test Bed

This program will be offered in the Testbed at the same time as the program is offered in the remainder of the service territory.

Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory

April 24, 2018

Prepared For

Portland General Electric

Prepared BY

Gabe Kwok
Ben Haley

EVOLVED ENERGY RESEARCH

Contents

Executive Summary

Background

Portland General Electric (PGE) retained Evolved Energy Research to undertake an independent study exploring pathways to deep decarbonization for its service territory. This study comes amidst a broad interest in decarbonization from customers and stakeholders, as well as policies and goals to promote clean energy and emissions reductions.

Since 2007, Oregon has had a goal of reducing statewide greenhouse gas (GHG) emissions by 75 percent below 1990 levels by 2050. Recently proposed legislation seeking to establish a cap-and-trade program in Oregon also proposes to tighten the statewide GHG reduction goal to 80 percent below 1990 levels by 2050. At the local level, the City of Portland and Multnomah County passed resolutions in June 2017 committing to 100 percent renewable electricity by 2035 and a complete transition to carbon-free energy by 2050.

These drivers to deeply decarbonize the economy would require a transformation of the energy system, and major choices will need to be made about which technologies play a role and how aggressively to pursue carbon reductions across different sectors. A substantial body of existing technical work shows that the electricity sector plays a pivotal role in a low-carbon transition, but the extent and type of role depends on choices made in other sectors.[1] For example, the level of electrification pursued in buildings and the decision to produce fuels from electricity, such as hydrogen from electrolysis, will have implications for electricity demand and the quantity of renewable electricity generation that will need to be developed.

Due to the potential impact on long-term planning, PGE sponsored this study to inform its Integrated Resource Planning (IRP) efforts. This study is intended to provide an understanding of: (1) the opportunities and challenges of achieving economy-wide deep decarbonization; and (2) the resulting implications for electricity system operations and planning.

Approach

The overarching emissions target for this study is an 80 percent reduction below 1990 levels by 2050 in energy-related CO_2 emissions. CO_2 emissions from fossil fuel combustion have been the predominant source of Oregon's historical GHG emissions, and, since 1990, they have accounted for approximately four-fifths of total GHG emissions in the state. This target would allow for fossil fuel combustion emissions of no more than 9.2 $MMTCO_2$ in 2050 for the state of Oregon. We allocate the statewide carbon budget to PGE's service territory using its projected share of Oregon's population, which is estimated to be 47 percent in 2050.[2] This results in a carbon budget of 4.3 $MMTCO_2$ in 2050 for the PGE service territory.

We designed three future energy scenarios that reduce emissions to comply with the 4.3 $MMTCO_2$ target. These scenarios are referred to as "deep decarbonization pathways" or "pathways", and they provide alternative blueprints for achieving deep decarbonization of the energy system.

[1] For example, see Williams, et al. (2014) and Haley, et al. (2016).

[2] Population growth rate projections from OEA (2013).

For each sector of the energy economy, we developed a range of measures to replace today's energy infrastructure with efficient and low-carbon technologies over the next three decades. For example, passenger travel currently provided by a gasoline vehicle is replaced by an electric vehicle, and a compact fluorescent (CFL) light bulb is replaced by a light emitting diode (LED) light bulb. Each pathway combines measures across sectors at the scale and rate necessary to meet the study's emissions target.

We use EnergyPATHWAYS, a bottom-up energy systems model, to estimate energy demand, emissions and costs for each pathway. Our analysis starts with the same model and approach we have previously used to evaluate deep decarbonization for the United States, the State of Washington and other jurisdictions. We developed a detailed representation of the PGE service territory energy system, including infrastructure stocks and energy demands for buildings, industry, and transportation. Our analysis incorporates an hourly dispatch of PGE's electricity system, which allows us to better understand fundamental changes to electricity supply and demand, such as how to balance very high levels of intermittent renewables and the impact of electrification on hourly electricity demand.

Pathways

Our study aims to provide an understanding of the broad choices available to achieve deep decarbonization across the economy and the potential implications on the electricity sector. To inform this understanding, we develop three plausible energy futures for PGE's service territory that achieve steep reductions in energy-related CO_2 emissions between now and 2050. These future energy scenarios outline: (1) potential sources and demands for energy types over time; and (2) the scale and timing of change over the next three decades.

Table 1 provides a high-level summary of the three pathways included in this study, where each scenario incorporates alternative emissions reduction strategies and technologies. One of the primary objectives of our scenario design was to reflect a broad range of outcomes for the electricity sector. The High Electrification pathway relies on electrifying space and water heating in buildings and deploying bulk energy storage to balance high levels of renewable generation. Passenger transportation is characterized by high levels of battery electric vehicles (BEV), while freight transportation includes both battery electric and hybrid diesel trucks. The Low Electrification pathway decarbonizes energy supply with a variety of renewable fuels, and electrolysis and power-to-gas facilities provide both electricity balancing services and decarbonized pipeline gas. Passenger transportation is primarily BEV, while compressed and liquefied natural gas trucks are incorporated in the freight transportation sector. The High DER pathway is highly electrified and distributed, with increased rooftop solar PV and distributed energy storage in buildings and industry. The Reference Case projects business-as-usual conditions, including the Oregon Clean Electricity and Coal Transition (OCEP) and Clean Fuels Program (CFP).

Table 1 Scenario Summary

Scenario	Description
High Electrification	Fossil fuel consumption is reduced by electrifying end-uses to the extent possible and increasing renewable electricity generation
Low Electrification	Greater use of renewable fuels, notably biofuels and synthetic electric fuels, to satisfy energy demand and reduce emissions
High DER	Distributed energy resources proliferate in homes and businesses, which also realize higher levels of electrification
Reference	A continuation of current and planned policy, and provides a benchmark against the deep decarbonization pathways

We are not choosing or recommending a pathway to 2050, and the scenarios presented above are not exhaustive. However, the pathways we have included in this study illustrate possible routes to a deeply decarbonized energy system and provide an understanding of trade-offs between complex decisions made by consumers and producers across the energy economy.

Key Findings

The three pathways evaluated in this study demonstrate that achieving deep decarbonization is both possible and there are multiple ways of doing so. Through this analytical exercise, we have identified a number of key findings, which we describe in detail below.

Common Elements to Achieve Deep Decarbonization

Although our pathways demonstrate that a variety of technologies and approaches are possible to realize a low-carbon economy, they also share common strategies, including: energy efficiency, decarbonization of electricity generation and electrification. These *three pillars* are common themes in all pathways, and the energy transformation from today to 2050 reflects: (1) a decline in per capita final energy consumption by approximately 40 percent; (2) a decrease in the carbon intensity of electricity generation to near zero; and (3) an increase in the share of energy coming from electricity or fuels produced from electricity from approximately one-quarter today to at least half by 2050. All three strategies are required and pursuing only one is insufficient.

Planning for a 2050 Energy System

In order to facilitate a pathway to 2050, new energy infrastructure will be required that is low-carbon and efficient. Transformation is required across all sectors with consumers and energy suppliers both playing a key role. The analysis identifies the scale and rate of change for each pathway, and highlights trade-offs between choices made to achieve deep decarbonization. One example is the choice of decarbonizing heat in buildings. Electrification of heat with heat pumps may require electricity distribution network upgrades to allow for growth in electricity demand, but they also provide a source of flexibility and efficient cooling services during the summer. The alternative is decarbonized pipeline gas that requires new central-station fuel production facilities, additional renewable generation and transmission network upgrades. *Both* choices require new infrastructure and highlight how long-term planning will need to address several uncertainties.

Energy Demand and Electricity Demand

Energy efficiency plays a crucial role in all pathways, and *total energy demand* in 2050 is approximately 10 to 20 percent below today's level, while the population grows by more than 40 percent. Despite overall energy demand decreasing, *electricity consumption* increases in all pathways. By 2050, retail electricity sales are projected to increase by 60 to 75 percent relative to today's level. As a result, electricity's share of overall energy demand is projected to increase in a deeply decarbonized future.

Transportation Electrification

Electrification of passenger transportation is a critical component of decarbonizing the energy system, and passenger vehicles are at least 90 percent BEV by 2050 across all pathways. To ensure these vehicles are on the road by 2050 requires consumer adoption to be near 100 percent of vehicle sales during the mid-2030s. Delays in adoption increase the likelihood of missing the 2050 target.

Widespread adoption of electric vehicles (EVs) is projected to be the largest source of increased electricity consumption, and, left unmanaged, would increase peak demand. However, the fleet of EVs across PGE's service territory can employ smart charging by shifting their demand to more efficient times of day. Charging off peak, such as when renewable generation is high or during the middle of the night can mitigate peak load impacts while ensuring that passengers complete all of their intended trips.

Scale of Renewable Resources

Oregon's existing renewable portfolio standard (RPS) requires half of the energy PGE delivers to its customers to come from qualifying renewable resources by 2040. Deep decarbonization extends that ambition in two ways. First, the overall electricity generation mix is more than 90 percent carbon-free by 2050, including onshore wind, solar PV, hydro and geothermal resources. Second, the total quantity that must be generated (in average megawatts) increases due to: (a) electrification of end-use demand, such as heating and transportation; and (b) producing fuels from electricity, such as hydrogen and synthetic natural gas. As a result, the installed capacity of renewables is substantially higher than what's anticipated in any current planning proceedings and is more than double the quantity we would expect under current RPS policy.

Rooftop solar PV can play a key role in electricity supply, but its share of the overall electricity generation mix in a deeply decarbonized energy system is limited by the resource quality in Northwest Oregon (i.e., low capacity factors) and growth in electricity consumption. Distributed solar reduces the need for, but does not completely replace, transmission-connected renewables. Although the Low Electrification pathway has the lowest retail energy deliveries by 2050, the pathway requires the highest level of transmission-connected renewable generation due to electric loads from producing hydrogen and synthetic natural gas.

The scale of renewable resource development present in all scenarios highlights the need for proactive planning to ensure that these resources are available to come online in a timely fashion. This includes identifying promising areas for resource development, possible transmission network upgrades to ensure renewable generation is delivered to load, and operational considerations to balance a highly renewable electricity grid.

Balancing the Electricity System

Electricity systems must be continually balanced across several timescales, from seconds to daily, weekly and seasonal changes. Today, generation from thermal and hydro resources is varied to meet changes in demand. However, balancing electricity supply and demand becomes more challenging when inflexible, variable renewable generation is the principal source of electricity supply. For example, renewable generation exceeds load in approximately half of all hours in 2050 in our pathways.

This operational paradigm necessitates a transition to new forms of balancing resources to integrate renewables and avoid curtailment. New sources of flexibility, including energy storage and flexible demand, can complement traditional sources of flexibility. Flexible demand includes both: (a) flexible end-use loads, such as smart EV charging and water heating; and (b) flexible transmission-connected loads, such as electrolysis and power-to-gas facilities that produce low-carbon fuels. The portfolio of available balancing options depends on choices made across the energy economy.

I. Background

Portland General Electric (PGE) retained Evolved Energy Research to undertake an independent study exploring pathways to deep decarbonization for its service territory. This study comes amidst a broad interest in decarbonization from customers and stakeholders, as well as policies and goals to promote clean energy and emissions reductions at the state and local level. Transitioning towards a low-carbon energy economy will have significant implications for electricity supply and demand, and the various technologies and strategies deployed during this transformation can result in broad outcomes for the electricity sector. Due to the potential impact on long-term planning, PGE sponsored this study to inform its Integrated Resource Planning (IRP) efforts and provide an understanding of: (1) the opportunities and challenges of achieving economy-wide deep decarbonization across its service territory; and (2) the resulting implications for electricity system operations and planning.

A. Motivation and Context

Oregon has long been at the forefront of recognizing the risks imposed by climate change. In 2007, the Oregon legislature passed House Bill 3543 (HB 3543), which established GHG reduction goals, including: (a) 10 percent reduction below 1990 levels by 2020; and (b) 75 percent reduction below 1990 levels by 2050. The Oregon Global Warming Commission (OGWC) was established through the same bill, and later recommended an interim goal of a 40 percent reduction below 1990 levels by 2035.

Recently proposed legislation seeking to establish a cap-and-trade program in Oregon also proposes to tighten the statewide GHG reduction goal. The proposed legislation would require a reduction in statewide GHG emissions to: (a) a goal of 20 percent below 1990 levels by 2025; (b) a limit of 45 percent below 1990 levels by 2035; and (c) a limit of 80 percent below 1990 levels by 2050.

Oregon has existing climate policies targeting specific sectors. The Clean Fuels Program requires the average carbon intensity of transportation fuels to be reduced by 10 percent between 2015 and 2025. The state adopted a Renewable Portfolio Standard (RPS) in 2007, which requires a percentage of retail electricity sales to be met by qualifying renewable electricity generation. This policy originally required 25 percent of load to be met by renewables by 2025. Senate Bill 1547 (SB 1547), also known as the Oregon Clean Electricity and Coal Transition (OCEP), was passed in March 2016 and requires: (1) an increase in the RPS to 50 percent renewables by 2040; and (2) removing coal-fired electricity generation from the state's electricity supply by 2035.

PGE's 2016 IRP reflected the increase in renewable energy requirements and transition from coal generation called for in the OCEP. Throughout the IRP process, stakeholders and customers have expressed interest in low-carbon portfolios and exploring deep emissions reductions. In addition, the City of Portland and Multnomah County passed resolutions committing to ambitious clean energy goals shortly after, including: (a) 100 percent renewable electricity by 2035; and (b) a complete transition to carbon-free energy by 2050.

These drivers to deeply decarbonize the economy would require ambitious energy system transformation. Prior studies examining similar levels of GHG reductions for the states of Washington and California, the United States and countries representing more than 75 percent of global GHG emissions have all identified the following required changes to their future energy systems: (1) highly efficient use of energy; (2) generating electricity with low- and zero-carbon resources; and (3) substituting fossil fuels with electricity and electricity-derived fuel.[3] Pursuing only one change, such as decarbonizing electricity generation, is insufficient to meet economy-wide goals and all three strategies are needed.

In addition to these common themes, there are a range of alternative strategies that make it possible to achieve the same GHG goal. Different technologies and fuels can be deployed to decarbonize energy supply and demand, and the extent of decarbonization by end-use sector may vary. Key differences between pathways identified in prior studies include the level of end-use electrification and the allocation of limited bioenergy resources to decarbonize gaseous and liquid fuels.

As a result, long-term planning for the electricity sector will need to account for decarbonization efforts in other sectors and the complex mix of choices that may be pursued. Examples of actions that would affect long-term electricity planning include: (a) adoption of high levels of electric vehicles in the transportation sector, which affects overall electricity demand and its shape; (2) production of synthetic electric fuels, such as hydrogen from electrolysis, which will increase the demand for clean electricity generation; and (3) deployment of distributed energy resources across homes and businesses. However, the likelihood and timing of these developments and other potential decarbonization efforts is uncertain.

Our study aims to provide an understanding of the broad choices available to achieve deep decarbonization across the economy and the potential implications on the electricity sector. To inform this understanding, we develop a range of plausible energy futures for PGE's service territory that achieve steep reductions in energy-related CO_2 emissions between now and 2050. These future energy scenarios outline: (1) potential sources and demands for energy types over time; and (2) the scale and timing of change over the next three decades.

B. Study Scope

Our study scope includes designing and evaluating three future energy scenarios that deeply decarbonize the PGE service territory's energy system. We refer to these scenarios throughout the report as "deep decarbonization pathways" or simply "pathways". We also developed a Reference Case reflecting current policy to provide a benchmark against the pathways scenarios.

The primary results of our study include projections from today to 2050 of: (1) energy demand by sector and type; (2) energy supply; (3) energy-related CO_2 emissions; and (4) energy system-related costs. This is supplemented by detailed results for the electricity sector, including electricity demand, installed capacity, generation, and hourly dispatch results for PGE's bulk power system.

Given our focus on exploring energy system transformation, we account for all forms of energy (e.g., gasoline, pipeline gas, hydrogen) and our analysis is not limited to electricity. We include CO_2 emissions from energy use, but we do not track non-energy CO_2 and non-CO_2 GHGs. The geography for our analysis is confined to PGE's service territory and excludes the rest of Oregon. Since one of the primary objectives of the study is to explore economy-wide compliance with a GHG target, we include load from customers that are currently under direct access to account for all energy use.

[3] These strategies are commonly referred to as the "three pillars".

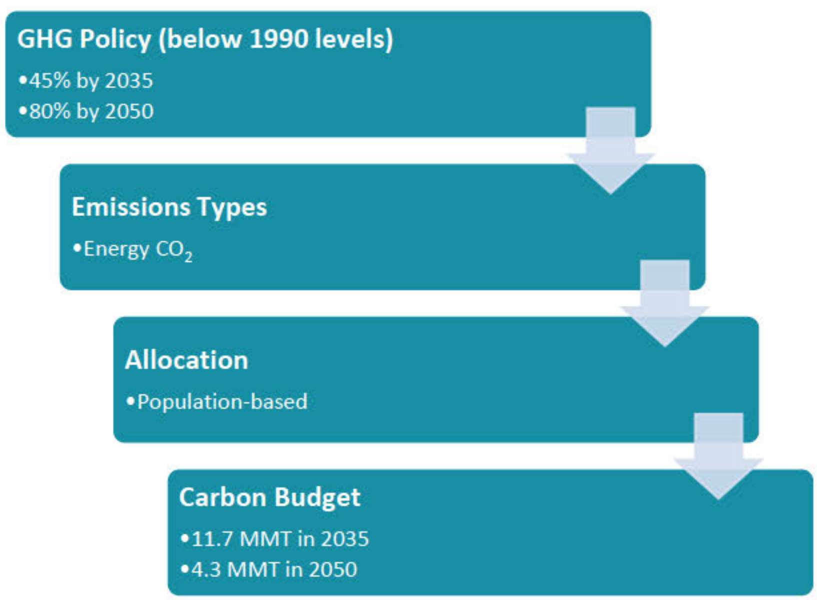
Given the exploratory nature of this study, it is important to emphasize what this study *is not*:

- Our scenarios are not a forecast of the future;
- We are not predicting future outcomes or assigning probabilities to scenarios;
- We are not choosing or recommending a pathway to 2050;
- Scenarios assessed here are not exhaustive and thousands of plausible alternatives exist;
- Scenarios do not reflect PGE's business plan or future resource acquisitions; and
- This study's modeling approach and results do not replace existing tools or processes used in IRP, such as defining "need" for resource adequacy or identifying optimal portfolios, nor do they replace cost-effectiveness evaluation, etc.

C. Study Emissions Target

For the purposes of this study, the energy-related CO_2 emissions budget for PGE's service territory is 11.7 million metric tons ($MMTCO_2$) in 2035 and 4.3 $MMTCO_2$ in 2050. Developing an appropriate emissions budget to evaluate deep decarbonization requires numerous assumptions to account for: (a) the fact that currently there is no binding, economy-wide GHG policy covering PGE's service territory; (b) any state-wide emissions limit must be translated into a budget for PGE's service territory; and (c) the scope of our work includes energy-related CO_2 emissions and excludes non-energy CO_2 and non-CO_2 GHGs. Our approach for deriving the study's emissions budget is summarized in Figure 1 and further described below:

Figure 1 Approach to Develop Study's CO_2 Target



- **GHG Policy**. The context for emission reductions, discussed in the proposed cap-and-trade legislation, requires a reduction in statewide GHG emissions to: (a) 45 percent below 1990 levels by 2035; and (b) 80 percent below 1990 levels by 2050.

- **Emissions Types**. CO_2 emissions from fossil fuel combustion have been the predominant source of Oregon's historical GHG emissions, and, since 1990, energy-related CO_2 emissions have accounted for four-fifths of total gross GHG emissions in the state. For simplicity, we apply the emissions reductions from the above GHG policy to Oregon's 1990 energy-related CO_2 emissions, which were approximately 46 $MMTCO_2$.[4] This results in a state-wide budget for CO_2 emissions from fossil fuel combustion of approximately 25.2 $MMTCO_2$ in 2035 and 9.2 $MMTCO_2$ in 2050. Based on a state population forecast of 5.59 million in 2050, this results in a per capita emissions budget of 1.6 tCO_2 per person, which is consistent with prior decarbonization studies.
- **Budget Allocation**. We allocate the state-wide emissions budget to PGE's service territory using its projected share of Oregon's population. In 2015, the PGE service territory included approximately 1.8 million people or 45 percent of Oregon's population. Projections of long-term population growth show counties within PGE's service territory growing at a slightly faster rate than the state as a whole. PGE's share of the state's population is projected to increase to 46.3 percent in 2035 and 47 percent by 2050. This translates into a carbon budget of 11.7 $MMTCO_2$ in 2035 and 4.3 $MMTCO_2$ in 2050.

The carbon budget we have developed for PGE's service territory is specific to this study. Any future policy mechanisms used to achieve emissions reductions, such as a price on carbon or complementary measures, may result in alternative emissions outcomes than those modeled here. In other words, the *total* statewide GHG emissions target may be compliant in the future, but *where* mitigation occurs is not definite. For example, more or less mitigation may occur between: (a) PGE's service territory and the rest of Oregon; (b) buildings and the industrial sector; and (c) sources of energy CO_2 and other GHGs.

[4] We note that our approach implicitly assumes that non-energy CO_2 and non-CO_2 GHGs will be reduced on an equivalent percentage basis in order to achieve the overall GHG targets. Historical emissions data from DEQ (2016).

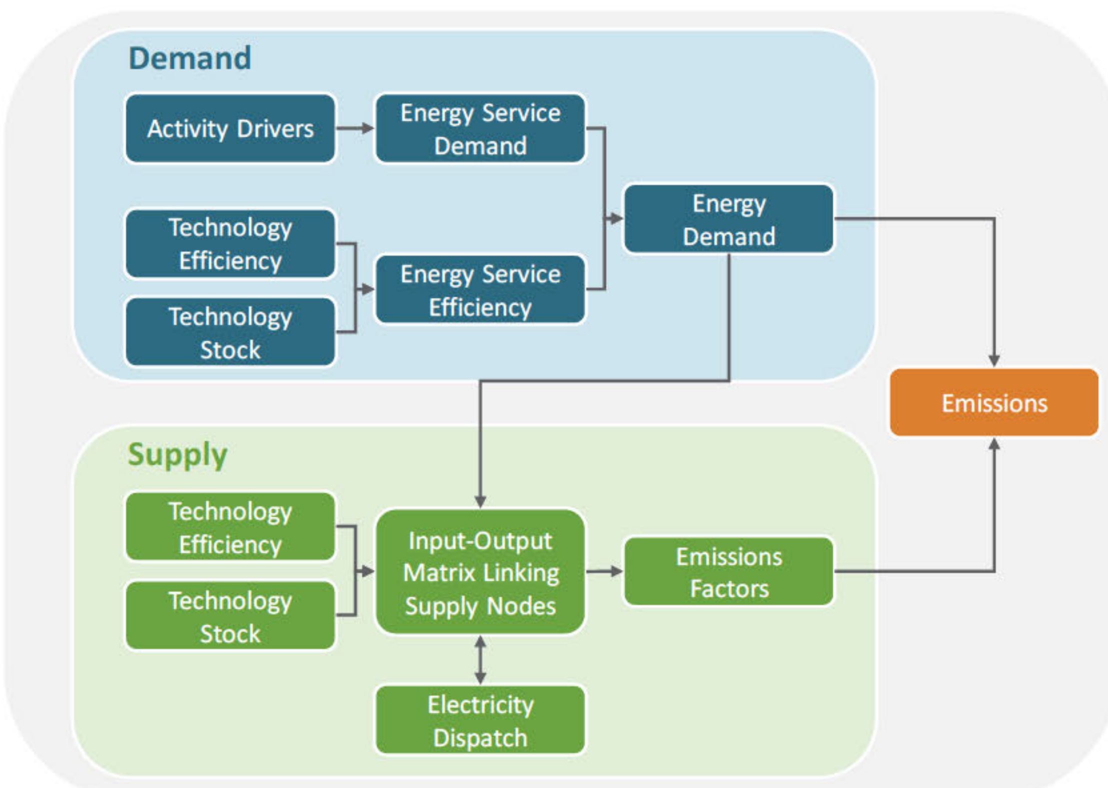
II. Study Assumptions and Approach

A. EnergyPATHWAYS Modeling Framework

We use EnergyPATHWAYS, a bottom-up energy systems model, to estimate energy demand, emissions and costs for each future energy scenario. Our analysis starts with the same model and approach we have previously used to evaluate deep decarbonization for the United States, the State of Washington and other jurisdictions. We developed a detailed representation of the PGE service territory's energy system, including infrastructure stocks and energy demands for buildings, industry, and transportation. Our analysis incorporates an hourly dispatch of PGE's electricity system, which allows us to better understand fundamental changes to electricity supply and demand, such as how to balance very high levels of intermittent renewables and the impact of electrification on hourly load.

Figure 2 depicts the general structure of EnergyPATHWAYS with the demand- and supply-side of the energy system shown separately. The demand-side calculates the quantity of energy demanded by different services at the technology level, such as the kWh of electricity and therms of pipeline gas demanded by water heaters in the residential sector. The supply-side determines how energy demand is met, such as the share of electricity provided by gas-fired combined cycle power plants, onshore wind power plants and rooftop solar PV. The energy system is simulated in sequence with the demand-side run prior to the supply-side.

Figure 2 General Structure of EnergyPATHWAYS



The demand-side starts with exogenous projections of activity drivers, such as population, households, commercial floorspace and industrial value of output. These drivers serve as the basis for projecting demand for energy services. For example, as the number of total residential households and square footage increases, then the demand for lighting will similarly increase. The technology composition of the stock along with the efficiency of each technology creates a service efficiency. In the lighting example, a transition from incandescent to CFL and LED light bulbs would improve service efficiency. Energy service demand and service efficiency are then combined to calculate the demand for energy, while the fuel type depends on the stock of technologies used to satisfy the demand for energy services.[5]

The supply-side is characterized by an input-output (IO) matrix that specifies the flow of energy between "supply nodes" that produce or deliver energy. Examples of supply nodes include power plants and transmission and distribution infrastructure. The coefficients in the matrix specify the amount of input energy required to produce one unit of output energy. For example, a gas-fired combined cycle power plant with a heat rate of 6,824 Btu/kWh (50% efficiency) would require 2.0 units of natural gas to generate 1.0 unit of electricity. These coefficients are dynamic and reflect: (1) changes in the composition and efficiency of supply-side technologies; and (2) outputs from an hourly electricity dispatch (i.e., the generation mix). From this process, emission factors are developed for each fuel. Finally, the emission factors from the supply-side are combined with final energy demand from the demand-side to estimate system-wide emissions.

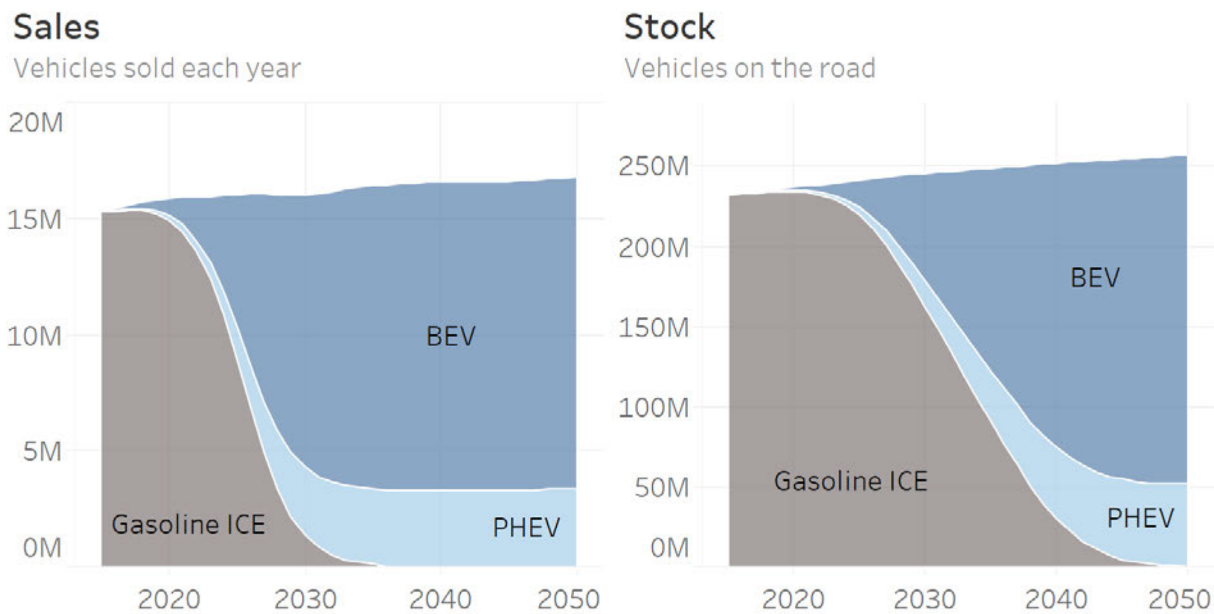
To reduce emissions, we develop measures to replace existing demand- and supply-side equipment and infrastructure with efficient and low-carbon technologies. For example, passenger travel currently provided by a gasoline vehicle is replaced by an EV, and a CFL light bulb is replaced by an LED light bulb. Future energy scenarios are designed by combining measures across sectors at the scale and rate necessary to meet the study's emissions target.

We implement measures through a stock rollover process, where a portion of energy infrastructure retires in each year and must be replaced by new energy infrastructure. In a baseline scenario, retiring infrastructure is generally replaced with the same category of technology, but the cost and performance characteristics reflect the more recent installation year (e.g., a retiring reference dishwasher is replaced by a new reference dishwasher). Alternatively, measures specify the composition of new energy infrastructure (e.g., half of vehicle sales are plug-in hybrid electric vehicles by 2025).

The stock rollover process is illustrated for light-duty vehicles in Figure 3, where the measure shown on the left-hand side of the chart specifies that sales of new light-duty vehicles are 80 percent BEV and 20 percent PHEV by 2035. Changes to the vehicle stock, shown on the right-hand side, are moderated by this process and BEV/ZEV vehicles do not make up all vehicles on the road until 2050. All scenarios in this study assume that infrastructure is retired naturally (i.e., at the end of its lifetime), and there are no early retirements.

[5] A portion of electric energy can be dispatched (i.e., flexible load), and this process is modeled on the supply-side.

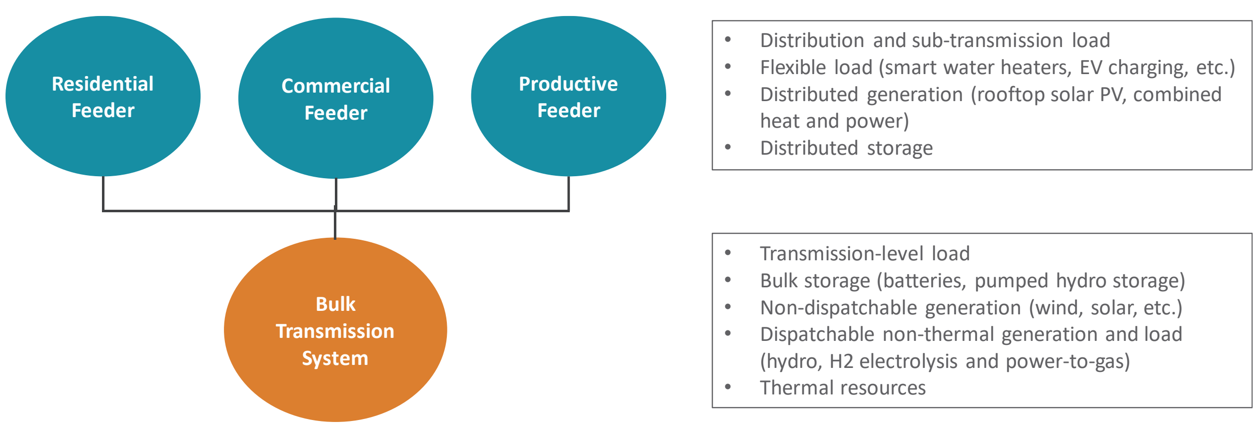
Figure 3 Illustrative Example of Stock Rollover in EnergyPATHWAYS



B. Electricity Sector Modeling

Electricity system operations in EnergyPATHWAYS are modeled on an hourly basis for each year through 2050. This includes a detailed representation of loads and resources at the feeder-level and the bulk transmission system. The structure of the electric system is shown in Figure 4 below, with the boxes illustrating the type of resources included within each node. Electricity dispatch and the development of load shapes are further described below, and we illustrate our approach for a three-day period (February 6-8, 2050).

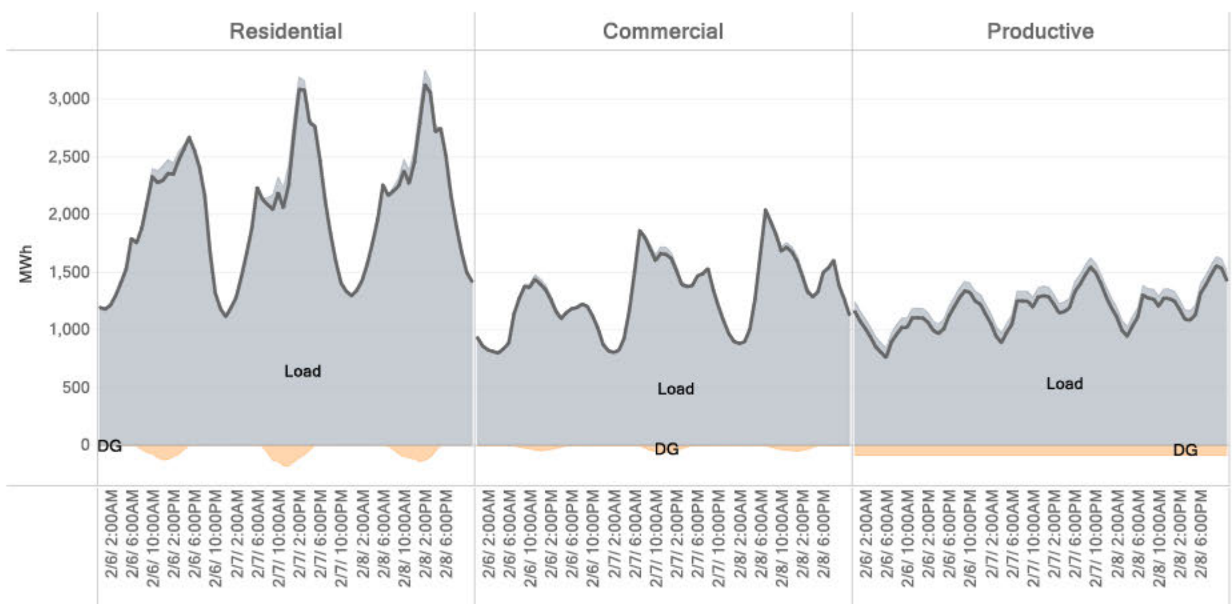
Figure 4 EnergyPATHWAYS Electricity System Structure



System load shapes are developed from the "bottom-up" by multiplying hourly sector, sub-sector, and technology-specific load shapes by the associated annual electricity consumption.[6] The bottom-up shape is then calibrated against a historical, top-down system load shape. Going forward, the system load shape changes in each year as the contribution from end-uses evolves. For example, as LED lighting penetration increases, then night-time demand will decrease due to their higher efficiency relative to incandescent and CFL light bulbs. In addition, the electrification of space heating will increase electric load during winter hours to account for the contribution of heating during winter months.

Sub-sector loads are aggregated to sectors and mapped to a "stylized" residential, commercial and/or productive (industrial) feeder, which models customer type at the distribution level. This is primarily to allocate electric vehicle charging, which could take place at home or at the workplace, onto the electricity distribution system. Distributed generation, such as combined heat and power (CHP) and rooftop solar PV resources are modeled across feeders. Figure 5 shows load and distributed generation for three feeders with the net load shown as the black line.

Figure 5 Distribution System: Net Load



Note: figure is illustrative.

The bulk transmission system receives the distribution-level net load and combines them with transmission-level loads, such as electrolysis and power-to-gas facilities. Output from non-dispatchable resources on the transmission system, such as wind, solar, geothermal and run-of-river hydro, is then accounted for to produce an initial system net load signal, as shown in Figure 6 below. During this three-day snapshot, the minimum net load in a single hour is -4,734 MW due to the coincidence of high wind and solar generation.

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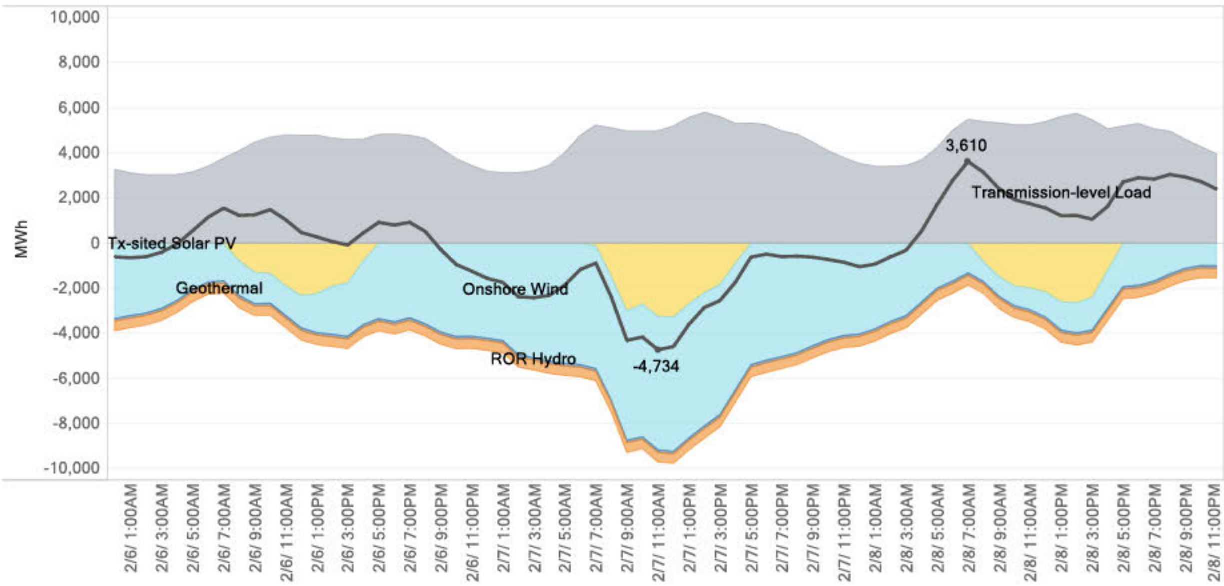
[6] Load and resource shapes reflect 2011 weather conditions.

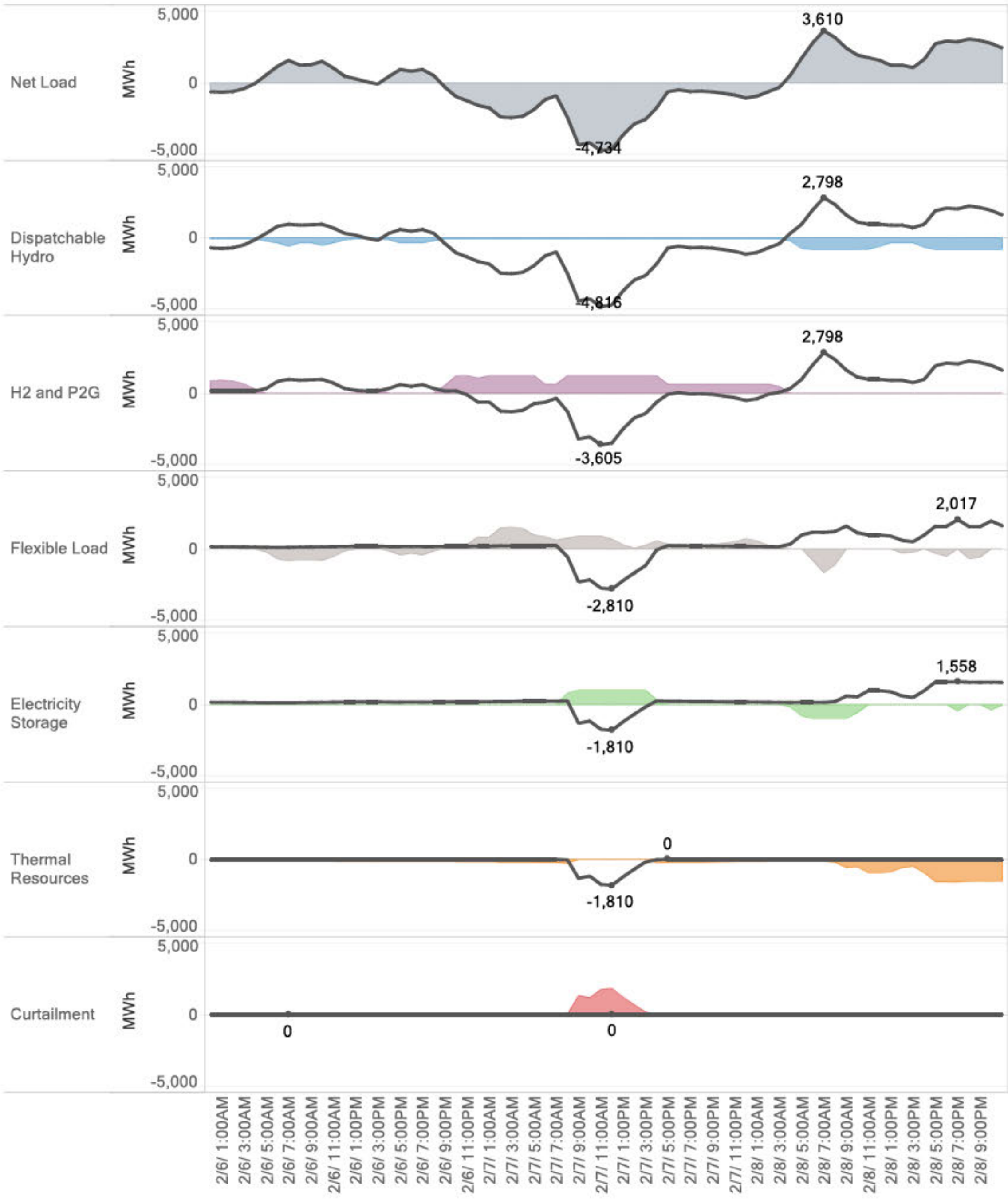
Figure 6 Transmission System: Net Load



Note: figure is illustrative.

Figure 7 illustrates the dispatch of flexible resources in sequence, with each resource dispatching to minimize the net load peaks and valleys. During the three-day period, net load starts with a maximum of 3,610 MW and and a minimum of -4,734 MW. Flexible, carbon-free resources, including dispatchable hydro plants, electric fuel production facilities, flexible loads and energy storage, flatten the net load to a maximum of 1,558 MW and a minimum of -1,810 MW. Thermal generators are dispatched in order of marginal cost to serve the remaining positive net load, while the remaining negative net load is curtailed.

Figure 7 Flexible Resource Dispatch



Note: figure is illustrative.

We model all generation resources in PGE's system, including existing power plants and contracts. The capacity of these resources was provided by PGE, and we developed plant heat rates (efficiencies) for thermal resources based on historical generation and fuel input data from Form EIA-923. Hydro resources are differentiated between dispatchable (e.g., Pelton-Round Butte) and run-of-river, and both resources types are constrained by a monthly energy budget. For imports, we use projected electricity market prices (in $/MWh) and natural gas prices (in $/MMBtu) provided by PGE to develop market heat rates (in MMBtu/MWh) to both cost and assign an emissions intensity.

We use the following heuristic to ensure the quantity of installed generating capacity meets system load in every hour of the year. First, "annual capacity need" is estimated as the maximum hourly net load plus operating reserves. Next, the installed capacity of dispatchable resources is de-rated by their forced outage rate to estimate their contribution. Finally, generic capacity resources are added to fill any gap between "annual capacity need" and the contribution of dispatchable resources. We assume generic capacity resources have the cost and performance characteristics of a frame type combustion turbine, which is consistent with PGE's IRP.

We note that our modeling results may differ from PGE's IRP due to the use of alternative models and the inclusion of direct access loads in our scope. We describe the electricity resources for each scenario in Section III.B.1 below.

C. Energy Demand and Supply

EnergyPATHWAYS was originally developed to assess deep decarbonization for the United States, and most of the energy demand and supply inputs are drawn from the EIA's National Energy Modeling System (NEMS) that produces the *Annual Energy Outlook*.[7] NEMS input data is comprehensive of the U.S. energy system and internally consistent. The primary geography for energy demand in NEMS is the census division, which each include a collection of states. For example, the Pacific census division includes Washington, Oregon and California, while the Mountain census division aggregates the remaining states in the West.

Given the common input data and energy system representation, EnergyPATHWAYS also uses census division as the primary geography. However, the model is geographically flexible by accepting energy demand and supply input data at a variety of geographical resolutions (e.g., state-level) and mapping these together onto one consistent geography. We used this geographic mapping feature to develop the underlying energy system representation for PGE's service territory. Figure 8 illustrates this process, where energy system data for a variety of geographies is mapped to PGE's service territory. This "downscaled" energy data is combined with direct inputs of PGE's service territory to characterize the entire energy system. To allocate input data at various geographical resolutions to PGE's service territory, we used: (1) households by county in PGE's service territory; (2) land area (in square miles) by county in PGE's service territory; and (3) value of shipments of products by industrial sector by state of origin, which allows us to estimate the quantity of industrial activity within a given subsector and state.[8]

[7] For example, see Risky Business Project (2016).

[8] PGE provided county-level households and land area. Value of shipments data is from the Bureau of Transportation Statistics and Federal Highway Administration's 2015 Freight Analysis Framework.

Figure 8 Geographic Downscaling

Table 2 summarizes the primary input data sources for energy demand by subsector. We use the 2013 PGE Residential Appliance Saturation Survey (RASS) to characterize the existing stock of the residential space heating, air conditioning and water heating subsectors. This includes the composition of technologies and fuels used in single-family, multi-family and manufactured homes. Energy use intensity (energy consumption per stock) is derived from the EIA's Residential Energy Consumption Survey (RECS) and the Northwest Energy Efficiency Alliance's (NEEA) Residential Building Stock Assessment. Energy demand for the remaining residential subsectors (e.g., refrigerators, dishwashers, etc.) is from the EIA AEO 2017. Vehicle miles traveled (VMT) for light-, medium- and heavy-duty vehicles are from Oregon's 2017 Highway Cost Allocation Study (HCAS), while the remaining energy demand is primarily from the EIA's AEO 2017.

Table 2 Summary of Energy Demand Input Data

Demand Subsector	Input Data Sources	Input Data Geography
Residential Space Conditioning and Water Heating	PGE 2013 RASS Study: existing stocks	Service Territory
	EIA RECS and NEEA: energy use intensity	State
Other Residential Subsectors	EIA AEO 2017: energy demand	Census Division
Commercial Subsectors	NWPCC 7th Power Plan: square footage	State
	EIA AEO 2017: energy demand	Census Division
Industrial Subsectors	EIA AEO 2017: energy demand	Census Region
Passenger and Freight Transportation	2017 Oregon HCAS: vehicle miles traveled	State

We compared the initial bottom-up energy demand projections against top-down energy demand data from the EIA's State Energy Data System (SEDS), which includes historical energy demand by fuel and sector. We calibrated EnergyPATHWAYS to reconcile any differences between our near-term modeling outputs and historical data by scaling energy service demand or energy demand. We further calibrated electricity consumption by sector to ensure consistency with PGE's load forecast through 2050.

Energy demand projections are developed separately for a variety of final energy types, which can broadly be categorized as: (1) electricity; (2) pipeline gas; and (3) liquid fuels.[9] Table 3 summarizes the types of resources that can supply each final energy type, and the supply mix determines the emissions intensity of fuels. For example, electricity can be supplied by a variety of fossil and carbon-free

[9] Additional final energy types are modeled, but these represent the vast majority of final energy demand.

resources, and Section III.B.1 details electricity supply assumptions for PGE's service territory. Pipeline gas can be supplied with a mix of natural gas, renewable natural gas (RNG) produced from bioenergy, hydrogen (H2) produced through electrolysis, and synthetic natural gas (SNG) produced though power-to-gas (P2G). Liquid fuels are supplied by refined fossil sources, as well as fuels developed using bioenergy (i.e., renewable diesel and jet fuel).

Table 3 Final Energy Types and Supply Sources

Category	Final Energy Type	Supply Sources
Electricity	Electricity	Coal and natural gas (fossil); hydro; wind; solar PV; geothermal
Pipeline Gas	Pipeline Gas	Natural gas (fossil); RNG (biomethane); H2; SNG
	Compressed Pipeline Gas (CNG)	
	Liquefied Pipeline Gas (LNG)	
Liquid Fuels	Gasoline	Fossil gasoline; ethanol
	Diesel	Fossil diesel; renewable diesel
	Jet Fuel	Fossil jet fuel; renewable jet fuel

D. Biomass

Biomass is key resource for decarbonizing energy systems due to its versality, which allows for biofuels to directly replace both liquid and gaseous fossil fuels. Examples of conversion routes include renewable natural gas (RNG) that replaces natural gas and renewable diesel that replaces diesel. However, the supply of sustainable or net-zero carbon bioenergy resources is limited, and, in prior analyses, scarce bioenergy resources are allocated to fuels and sectors that are challenging to electrify, such as jet fuel for aviation.

In this study, we use the U.S. Department of Energy's *2016 Billion-Ton Report* as the primary source for the availability and cost of bioenergy resources. Given that the supply curve is for the U.S., we make the following assumptions. First, the PGE service territory's allocation of the national supply is its population-weighted share, which is equal to 7.3 million dry tons (MDT), as shown below:

$$PGE's\ share = \frac{PGE\ population}{U.S.population} \times U.S.supply\ of\ sustainable\ biomass\ feedstocks$$

$$7.3\ MDT = \frac{1.8\ million}{320.9\ million} \times 1{,}300\ MDT$$

Second, we assume that other jurisdictions pursue similar bioenergy-related actions, which means that the cost of producing and consuming biofuels reflects movement up the national supply curve. This assumption addresses two considerations: (1) for sub-national (e.g., state or utility service territory) deep decarbonization analyses, it would be unrealistic to assume individual jurisdictions all consume the same (low-cost) portion of the bioenergy supply curve; and (2) given the high cost of transporting biomass across long distances, it's likely that biofuels would be developed close to their source and transported across the country via the same networks that currently transport fossil fuels. Finally, we assume that the biomass feedstock is net-zero carbon, which results in biofuels with very low emissions rates due to some emissions from non-bioenergy use in conversion and refining processes.

E. Key Data Sources

Table 4 summarizes the key data sources used in our energy system modeling. We use data from PGE's 2016 IRP to characterize the cost and performance of electricity supply technologies and rely on the 2013 PGE RASS study to characterize the existing stock of residential appliances, as described above. This is supplemented by state and regional data sources, such as Oregon's Office of Economic Analysis (OEA) and the Northwest Energy Efficiency Alliance (NEEA). Most of the remaining sources are publicly-available reports produced by national laboratories, such as the U.S. Department of Energy (DOE).

Table 4 Overview of Key Data Sources

Category	Sources
Energy Supply Technology Cost and Performance	• PGE 2016 Integrated Resource Plan • NREL Annual Technology Baseline 2017 • EIA Form 923 • DOE Hydrogen Analysis (H2A) Project • ENEA Consulting (2016)
End-Use Technology Cost and Performance	• Input data for EIA's National Energy Modeling System (NEMS) used to produce the Annual Energy Outlook • NREL Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections
Building Stock Characteristics	• PGE 2013 Residential Appliance Saturation Study • NEEA Building Stock Assessment reports
Fossil Fuel Prices	• EIA Annual Energy Outlook 2017
Miscellaneous	• DOE 2017 Billion-Ton Report • FERC Form 714 • 2017 Oregon Highway Cost Allocation Study • OEA Forecasts of Oregon's County Populations and Components of Change, 2010 – 2050

Note: DOE is the U.S. Department of Energy; EIA is the U.S. Energy Information Administration; FERC is the Federal Energy Regulatory Commission; NEEA is the Northwest Energy Efficiency Alliance; NREL is National Renewable Energy Laboratory; and OEA is Oregon's Office of Economic Analysis.

III. Scenarios

A. Overview

Table 5 provides an overview of the three pathways included in this study, which each incorporate alternative emissions reduction strategies and technologies. One of the primary objectives of our scenario design was to reflect a broad range of outcomes for the electricity sector.

The **High Electrification** pathway relies on electrifying space and water heating in buildings and deploying bulk energy storage to balance high levels of renewable generation. Passenger transportation is characterized by high levels of battery electric vehicles (BEV), while freight transportation includes both battery electric and hybrid diesel trucks. The **Low Electrification** pathway decarbonizes energy supply with a variety of renewable fuels, and electrolysis and power-to-gas facilities provide both electricity balancing services and decarbonized pipeline gas. Passenger transportation is primarily BEV, while compressed and liquefied natural gas trucks are incorporated in the freight transportation sector. The **High DER** pathway is highly electrified and distributed, with increased rooftop solar PV and distributed energy storage in buildings and industry.

To provide a benchmark to compare the pathways against, we developed a **Reference Case** that projects business-as-usual conditions. This includes compliance with state-level policy such as the OCEP and CFP, as well as major federal policy such as improvements in corporate average fuel economy standards. The scenario is not designed to achieve an emissions target.

Table 5 Overview of Scenarios

Scenario	Description
High Electrification	Fossil fuel consumption is reduced by electrifying end-uses to the extent possible and increasing renewable electricity generation
Low Electrification	Greater use of renewable fuels, notably biofuels and synthetic electric fuels, to satisfy energy demand and reduce emissions
High DER	Distributed energy resources proliferate in homes and businesses, which also realize higher levels of electrification
Reference	A continuation of current and planned policy, and provides a benchmark against the deep decarbonization pathways

Although the future energy scenarios are characterized by alternative mitigation strategies, they are all constrained by a set of common scenario design principles. This conservative approach allays a broad range of concerns surrounding the technical feasibility and economic affordability of realizing a deeply decarbonized energy system, such as the need for revolutionary technological improvements or disruptive lifestyle changes. The scenario design principles in this analysis include: (a) applying the same demand for energy services; (b) replacing energy infrastructure at the end of its natural life (i.e., there are no early retirements); (c) using commercial or near-commercial technologies; (d) limiting the supply of sustainable bioenergy use; and (e) ensuring there are sufficient electricity resources to serve load in all hours. The sections below describe the energy supply and demand assumptions for each pathway.

B. Energy Supply

1. Electricity Resources

Table 6 summarizes our electricity supply assumptions for each pathway. Coal-fired resource assumptions are consistent with PGE's 2016 IRP and OCEP, where Boardman ceases operations by the end of 2020 and Colstrip units 3 and 4 are out of the resource mix by 2035. We assume the capacity of PGE's existing gas-fired resource fleet is online through 2050, while the amount of energy generated from these resources is a function of our electricity dispatch.

Hydroelectric resources include Pelton-Round Butte, run-of-river (ROR) hydro, Mid-C hydro and other contracts. We assume projected hydro resources and contracts are extended through 2050 (a total of 933 MW), and an additional 23 MW of small hydro is placed on-line in 2035. We assume new geothermal resources of 100 MW in 2035 and growing to 500 MW by 2050. Prior studies have identified 832 MW of conventional geothermal potential in Oregon with a further undiscovered enhanced geothermal system potential of 1,800 MW.[10]

The High DER pathway includes approximately 2,500 MW of behind-the-meter (BTM) solar PV resources across buildings and industry by 2050. We developed this target based on the technical potential of distributed solar PV across PGE's service territory identified in the 2016 IRP.[11] The High and Low Electrification pathways assume approximately 400 MW of BTM solar PV, which is two times the highest level of adoption from the same study.

Pathways rely on high levels of transmission-connected wind and solar PV to decarbonize electricity generation, including: (a) onshore wind located in the Pacific Northwest (PNW); (b) onshore wind located in central Montana; and (c) solar PV located in central Oregon. Approximately 75 percent of electricity generation comes from these resources in the High and Low Electrification pathways, and this level is lower in the High DER pathway due to the quantity of BTM solar PV resources. The installed capacity of these resources depends on the level of transmission-connected load.

Our Reference Case reflects current RPS policy (i.e., 50% in 2040) and any gap between the RPS obligation and generation from existing/projected qualifying resources is met with an equal amount of energy from PNW onshore wind and central Oregon utility-scale solar PV resources. Our analysis did not consider low-carbon generation from new carbon capture and storage (CCS) or nuclear resources.

[10] See Pletka and Finn (2009).

[11] See Table 1-3 of Black and Veatch (2015). Technical potential of 2,810 MW_{dc} translated to 2,555 MW_{ac} assuming an inverter loading ratio of 1.1.

Table 6 Electricity Supply

	High Electrification	Low Electrification	High DER
Coal	Boardman ceases operations by the end of 2020 Colstrip 3 and 4 out of the resource mix by 2035		
Gas	Maintain current fleet		
Hydro	Extend projected hydro contracts through 2050 (933 MW) Additional 23 MW of small hydro		
Geothermal	500 MW additional		
Behind-the-meter Solar PV	405 MW_{ac}		2,555 MW_{ac}
Utility-scale Wind and Solar PV	75% of electricity generation		67% of electricity generation

Note: values for 2050 unless specified otherwise.

The high levels of variable renewable generation included in the pathways necessitate balancing resources to ensure renewables are sufficiently integrated. Table 7 summarizes the flexible resource assumptions for each pathway, all of which include 36 MW/160 MWh of energy storage that comes online in 2021 to approximate PGE's proposed energy storage projects. Balancing in the High Electrification pathway is accomplished through 1,000 MW of bulk 8-hour energy storage, whereas the High DER pathway relies on 2,555 MW of distributed 6-hour storage, which is sized to the same capacity of distributed solar PV. No additional energy storage is developed in the Low Electrification pathway, which alternatively relies on flexible electrolysis and P2G loads. The size of these facilities depends on demand for hydrogen and synthetic natural gas, respectively.

All pathways incorporate flexible demand from select end-use sectors where: (a) load automatically shifts with changing electricity grid conditions; and (b) total electricity consumption does not change.[12] For example, the owner of an EV may wish to charge his or her vehicle when they arrive home, but they're willing to delay charging to later in the evening without affecting the ability to take future trips. Two promising electric loads to operate flexibility include: (1) loads that have a thermal storage medium (i.e., hot water heater) that can operate within a range and allow for flexible operation without service degradation; and (2) transportation loads that require battery storage, which can allow for flexible charging and state-of-charge management without degrading service.

We assume 75 percent of load from light-duty vehicles and water heaters in buildings is flexible by 2050, and 50 percent is flexible in residential space conditioning, residential clothes washing and drying, and commercial space heating subsectors. The amount of flexible load in each pathway depends on the level of electrification, and the higher quantity of electric appliances (e.g., heat pump water heaters) in the High Electrification and High DER pathways provides higher end-use demand flexibility relative to the Low Electrification pathway.

[12] Flexible load is further constrained by the number of hours load can be delayed and advanced in time.

Table 7 Balancing Resources

	High Electrification	Low Electrification	High DER
Energy storage	Proposed energy storage resources (36 MW / 160 MWh)		
	1,000 MW bulk 8-hour storage	No additional	2,555 MW distributed 6-hour storage
Flexible Electric Fuel Loads	Excluded	H2 electrolysis and P2G facilities	Excluded
Flexible End-Use Loads	Percent of electric load that is flexible by 2050: • Light duty vehicles = 75% • Residential and commercial water heating = 75% • Residential space conditioning = 50% • Residential clothes washing and drying = 50% • Commercial space heating = 50%		

2. Liquid and Pipeline Gas Fuel Blends

Table 8 summarizes our assumptions about the composition of pipeline gas, diesel and jet fuel in 2050. The Low Electrification pathway is characterized by several renewable fuels to decarbonize energy supply. Pipeline gas for buildings and industry is assumed to contain 15 percent renewable natural gas (RNG) and 15 percent synthetic electric fuels (H2 and SNG). The share of RNG is 85 percent in pipeline gas that is further liquefied or compressed for transportation vehicles, while the share of H2 and SNG is the same. Biomass is further used to produce liquid transportation fuels (e.g., renewable diesel). The High Electrification and High DER pathways assume no change to the supply of pipeline gas, with all biomass resources allocated to liquid transportation fuels.

Table 8 Liquid and Pipeline Gas Fuel Blend Assumptions in 2050

Type	Blend	High Electrification and High DER	Low Electrification	
		All Sectors	Res/Com/Ind	Transportation
Pipeline Gas	Natural Gas	100%	70%	0%
	RNG	0%	15%	85%
	SNG	0%	8%	8%
	H2	0%	7%	7%
Diesel	Fossil Diesel	0%	0%	0%
	Renewable Diesel	100%	100%	100%
Jet Fuel	Fossil Jet Fuel	0%	0%	0%
	Renewable Jet Fuel	100%	100%	100%

C. Energy Demand

1. Buildings and Industry

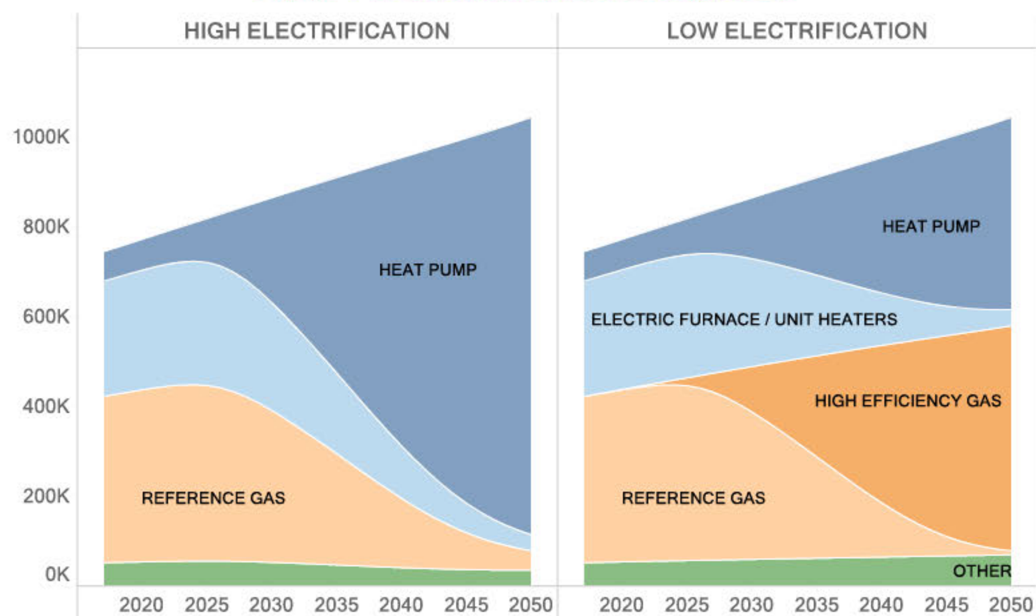
Table 9 summarizes the major low-carbon and efficient technologies in residential and commercial buildings. The High Electrification and High DER pathways are characterized by high levels of air source heat pump (ASHP) adoption for space heating and cooling needs, as well as efficient heat pump water heaters. The Low Electrification pathway relies on high efficiency gas-fired equipment to service space and water heating loads. In both pathways, lighting is provided by LEDs and the best available technology is adopted for other appliances, such as clothes washers, clothes dryers, refrigerators, etc.

Table 9 Predominant End-use Technologies in Buildings

	High Electrification and High DER	Low Electrification
Space Conditioning	Air source heat pump	High efficiency gas furnace High efficiency air conditioner
Water Heating	Heat pump water heater	High efficiency gas water heater
Lighting	LED	
Other Appliances	Best available technology	

We illustrate the change in today's building equipment by showing the evolution of the residential space heating stock through 2050 in Figure 9. Heat in the High Electrification and High DER pathways is largely provided by heat pumps, which includes both standard systems and ductless, mini-split heat pumps. In contrast, heat in the Low Electrification pathway is met by adopting high-efficiency natural gas furnaces, as well as pursuing electric energy efficiency by replacing electric furnaces and heaters with heat pumps.

Figure 9 Residential Space Heating Stock



We incorporated electrification measures in the High Electrification and High DER pathways for a limited number of industrial end-uses, including process heat and boilers. This was informed by NREL's Electrification Futures Study and includes adoption of electrotechnologies such as industrial heat pumps, resistance heating, induction furnaces and electric boilers.[13] These measures translate into electricity representing slightly less than 10 percent of final energy demand for industrial boilers and process heat by 2050.

2. Transportation

Table 10 summarizes our assumptions for vehicle sales shares in 2035 for passenger transportation and freight trucks. In all pathways, battery electric vehicles (BEV) are 90 percent of light-duty vehicle sales, while the remaining 10 percent is: (a) plug-in hybrid electric vehicles (PHEV) in the High Electrification and Higher DER pathways; and (b) hydrogen fuel cell vehicles (HFCV) in the Low Electrification pathway. We assume battery electric trucks account for half of freight truck sales, while the remaining 50 percent is: (a) hybrid diesel trucks consuming renewable diesel fuel in the High Electrification and High DER pathways; and (b) CNG and LNG trucks consuming decarbonized gas in the Low Electrification pathway.

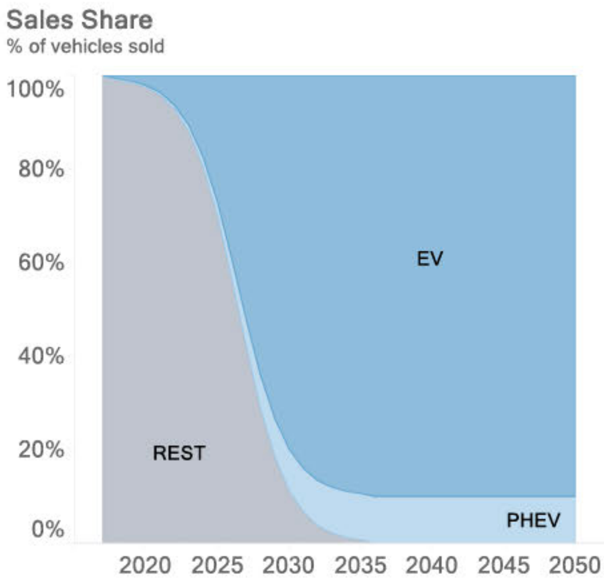
Table 10 On-Road Transportation Vehicle Sales Shares in 2035

Subsector	Technology Type	High Electrification and High DER	Low Electrification
Light-Duty Vehicles	Battery Electric	90%	90%
	Plug-in Hybrid Electric	10%	0%
	Hydrogen Fuel Cell	0%	10%
Medium-Duty Vehicles	Battery Electric	50%	50%
	Hybrid Diesel	50%	0%
	Hybrid CNG	0%	50%
Heavy-Duty Vehicles	Battery Electric	50%	50%
	Hybrid Diesel	50%	0%
	Hybrid LNG	0%	50%

Figure 10 shows how the assumptions in Table 10 change the stock of infrastructure over time, with light-duty vehicle sales shown on the left-hand side and the light-duty stock shown on the right-hand side. In the near-term, EV and PHEV light-duty autos and trucks make up a small portion of sales, but then increase to all vehicle sales in 2035. By the early 2030s, there are more than half a million EVs and PHEVs on the road, but the stock of vehicles does not completely turn-over to ZEVs until the mid-century.

[13] See Section 4 of P. Jadun, et al. (2017).

Figure 10 Light-Duty Vehicle Stock-Rollover: High Electrification Pathway



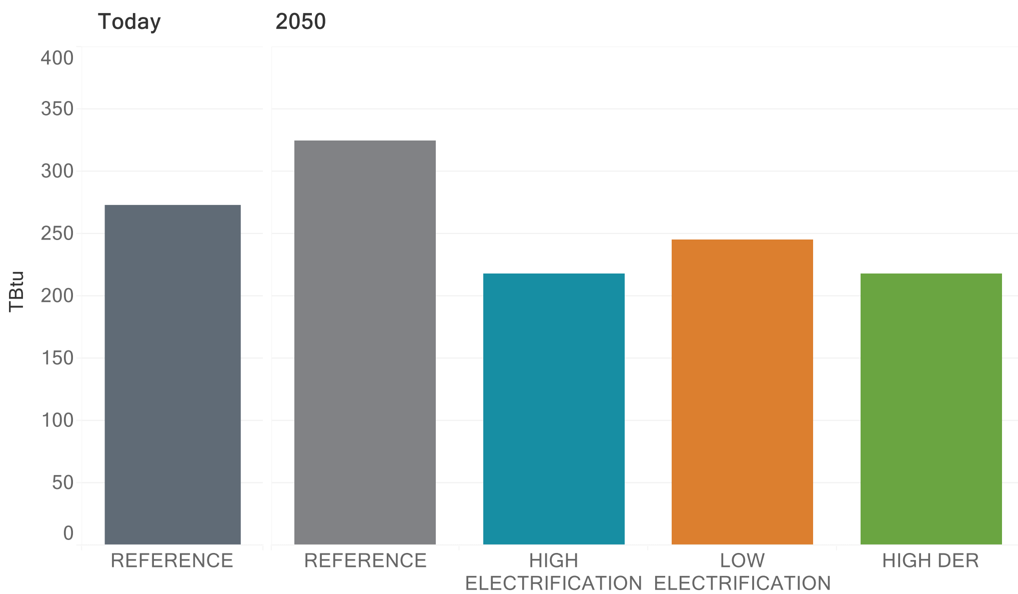
IV. Results: Energy System

In this section, we summarize the changes in the energy system for our future energy scenarios. We report several metrics for the energy system, including final energy demand, energy supply, energy related CO_2 emissions, and incremental energy system costs.

A. High-Level Summary

Reference Case final energy demand is projected to increase from 272 TBtu today to 325 TBtu, approximately a 20 percent increase, as shown in Figure 11 below. End-use demand is projected to increase as the drivers of energy use, such as population and economic activity, all grow through 2050. Final energy is used more efficiently in the pathways scenarios with a range of 218 to 245 TBtu by 2050, which represents a decrease of 25 to 33 percent below the Reference Case in 2050, and 11 to 19 percent below today's level.

Figure 11 Final Energy Demand



Energy-related CO_2 emissions are projected to slightly decrease (-4%) in the Reference Case between 2017 and 2050, as shown in Figure 12. This is largely due to existing policies decarbonizing electricity generation and transportation fuels being offset by growth in overall electricity consumption and vehicle miles traveled. Emissions for all three pathways are below the study's 2050 GHG target of 4.3 $MMTCO_2$. Emissions per capita decrease from 10.9 tCO_2 per person in 2017 to 1.6 tCO_2 per person in 2050, an 85 percent decrease.

Figure 12 Energy-related CO_2 Emissions

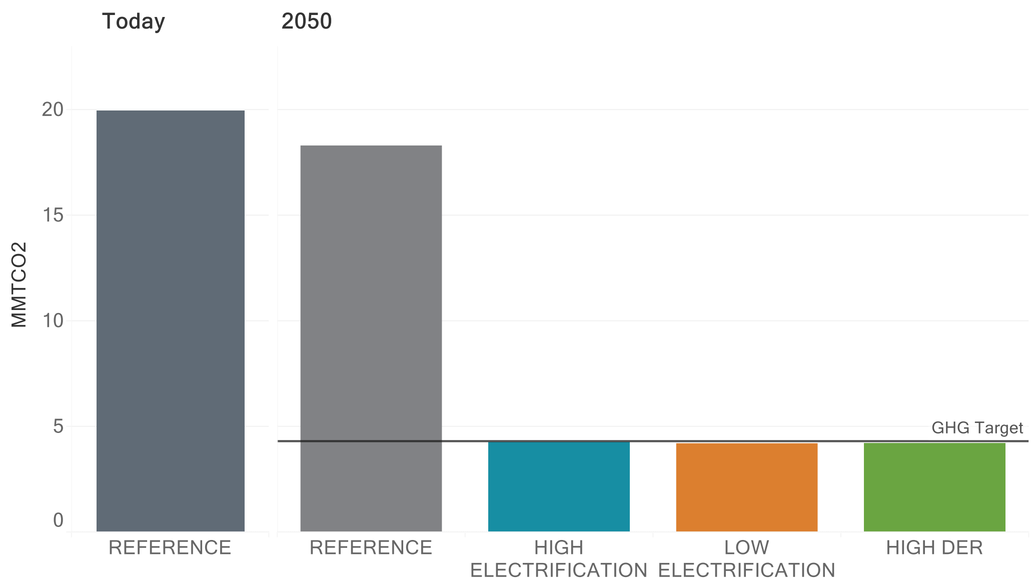
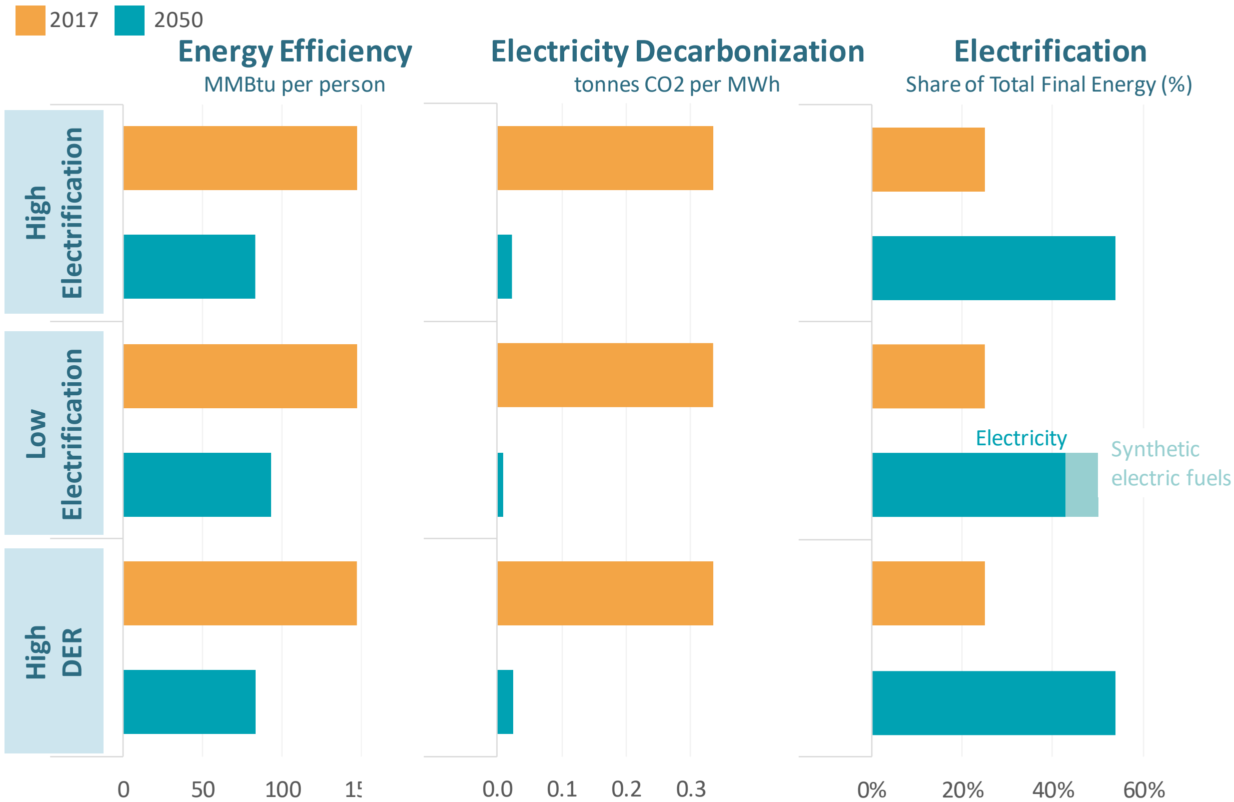


Figure 13 shows three metrics for decarbonization strategies (“three pillars”): (1) energy efficiency, which is estimated as final energy consumed per person; (2) electricity decarbonization, which is measured in tCO_2 emitted per MWh of generation; and (3) electrification, which is expressed as the share of total final energy that is electricity and electric fuels. Per capita energy consumption decreases from approximately 150 MMBtu per person today to between 83 and 93 MMBtu per person, a 37 to 44 percent decrease. This is accomplished without explicit reductions from baseline (Reference Case) energy service demand (e.g., vehicle miles traveled). The carbon intensity of electricity generation decreases by more than 90 percent and is below 0.03 tCO_2/MWh (300 kg CO_2/MWh) in all pathways. The percentage of electricity and electric fuels in total final energy increases from one-quarter today to at least half by 2050. In the Low Electrification pathway, the share of electricity is 43 percent (11 percentage points below the High Electrification pathway), but electric fuels make up 7 percent of total final energy, resulting in a total of 50 percent.

Figure 13 Three Pillars of Decarbonization

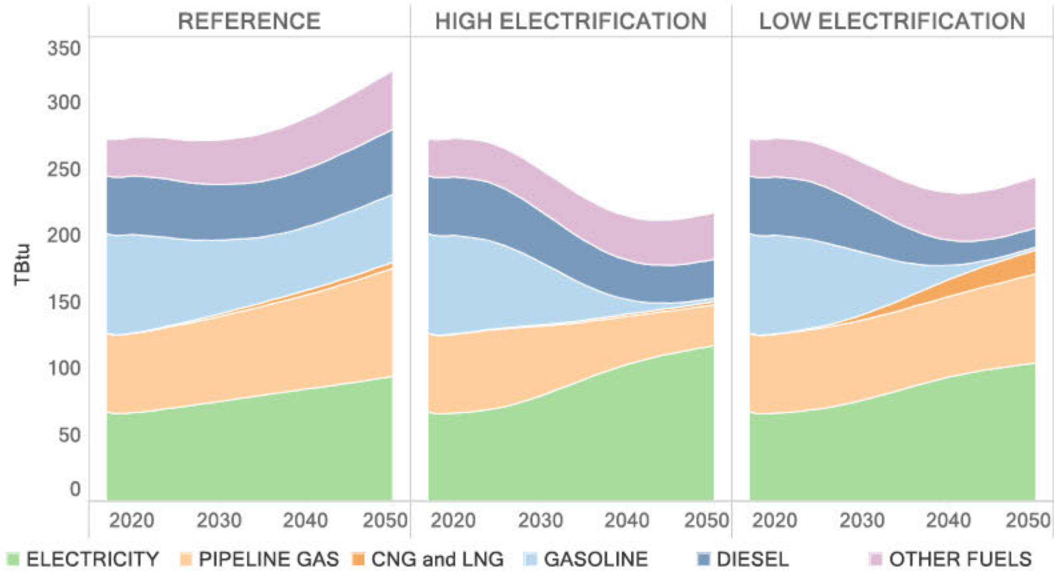


B. Energy Demand

Figure 14 shows end-use demand disaggregated by final energy type for each energy future.[14] The role of electricity expands across all pathways and increases from 25 percent of total end-use demand to 43 to 54 percent in 2050.[15] For comparison, the share of electricity only increases to 29 percent by 2050 in the Reference Case. Demand for liquid transportation fuels, such as gasoline and diesel, sharply decrease in all pathways. This decrease is compensated by higher demand for electricity, as well as CNG and LNG demand in freight transportation in the Low Electrification pathway.

[14] In this section, results for the High DER scenario are not shown, because final energy demand is equivalent to the High Electrification scenario. The impact of increased rooftop solar PV is accounted for when we show retail energy deliveries, which is discussed in Section V.A.
[15] This excludes synthetic electric fuels, which are categorized as "intermediate energy carriers".

Figure 14 Final Energy Demand by Type



Note: "Other Fuels" includes final energy types such as jet fuel, liquefied petroleum gas, biomass, and steam.

Figure 15 summarizes final energy demand for the residential, commercial, productive and transportation sectors. The figure shows Reference Case final energy demand growing over time, with decreases in the transportation sector (primarily due to fuel economy standards) offset by increases in buildings and industry. Total end-use demand decreases by 2050 for all pathways largely due to the efficiency improvements in passenger transportation related to adopting battery electric vehicles. As a result, the transportation sector's share of end-use demand decreases from approximately 46 percent today to 30 percent in 2050. Energy is used more efficiently in residential and commercial buildings, but the level of change varies across pathways based on technology adoption, which we discuss in more detail below.

Figure 15 Final Energy Demand by Sector

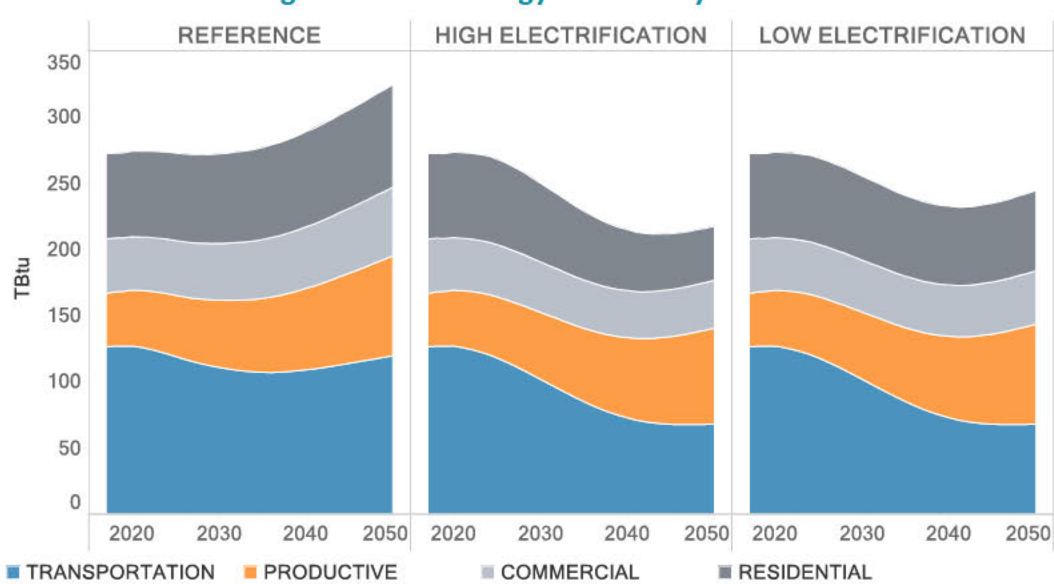
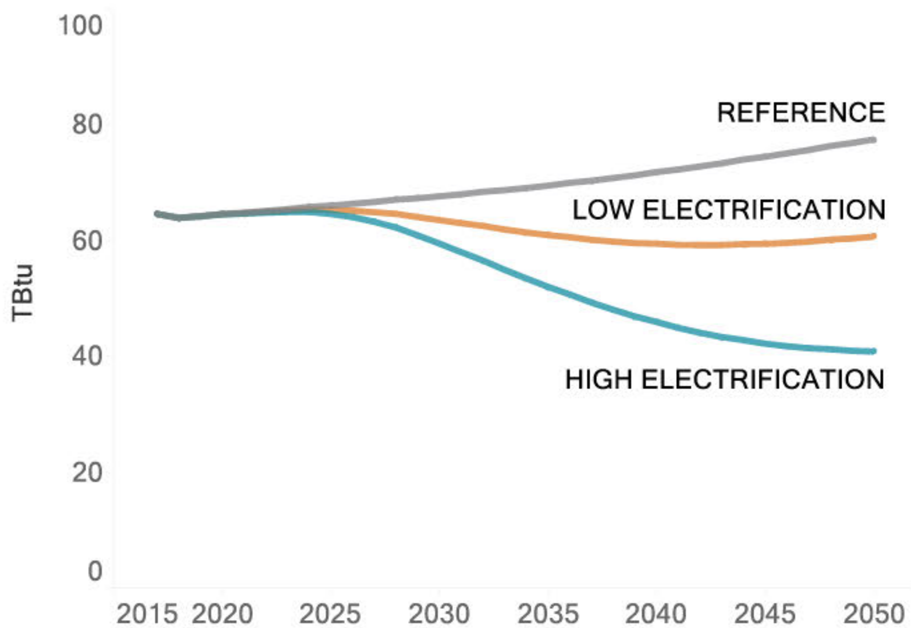


Figure 16 compares projections of residential energy demand and illustrates the improved use of energy in homes in the pathways scenarios relative to the Reference Case. All pathways include several electric energy efficiency measures, such as more efficient clothes washers and dryers, refrigerators, dishwashers and LED lighting. However, the large difference in final energy demand by 2050 between the High and Low Electrification scenarios is due to choices in space and water heating. The High Electrification pathway represents a world where households replace combustion-based furnaces and water heaters with air source heat pumps and heat pump water heaters, respectively. In the Low Electrification pathway, households adopt the most efficient gas furnaces and gas water heaters. However, the efficiency of heat pump technology relative to the best-in-class combustion equipment translates into deeper energy demand reductions.[16]

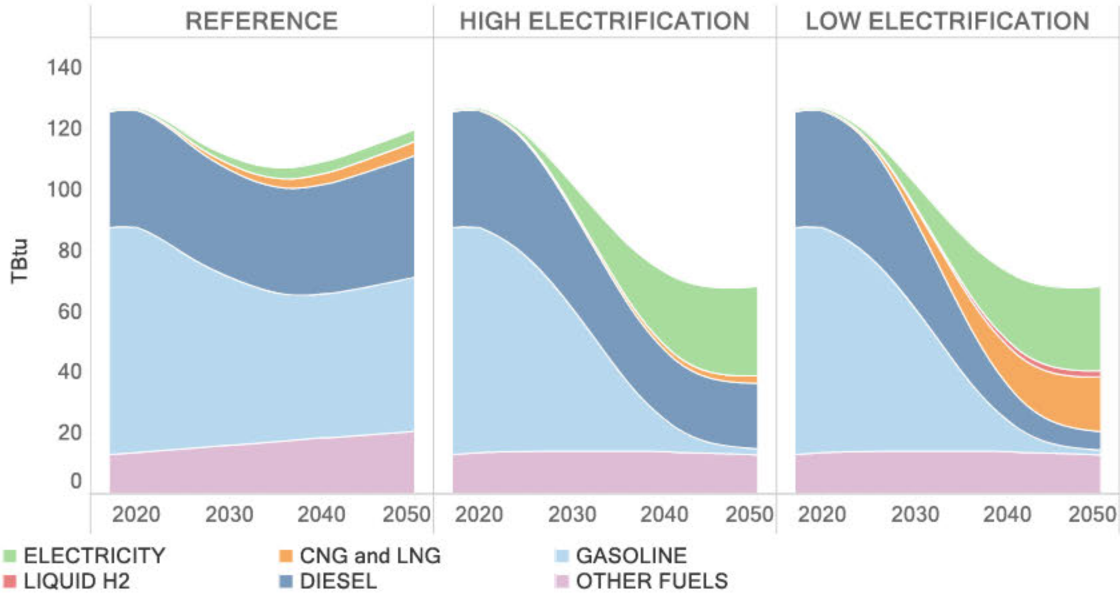
Figure 16 Residential Sector Energy Demand



The projections of energy demand for the transportation sector shown in Figure 17 reflect the changing composition of vehicles on the road. By 2050, the light-duty vehicle fleet is almost entirely electric vehicles, which results in significant decreases in gasoline fuel consumption and only modest increases in electricity consumption, because battery electric powertrains are more efficient than internal combustion engines. In all pathways, half of all freight trucks are electric by 2050, resulting in electricity becoming the largest transportation fuel type. The High Electrification pathway continues to use diesel fuel for the remainder of its freight trucks, but the supply is increasingly renewable diesel (100 percent by 2050). The Low Electrification pathway alternatively relies on hybrid CNG medium-duty trucks and LNG hybrid heavy-duty trucks. By 2050, demand from the CNG and LNG trucks in the Low Electrification pathway accounts for over 20 percent of total pipeline gas demand.

[16] For example, a high efficiency gas furnace has an annual fuel utilization efficiency (AFUE) of 0.98, whereas a standard air source heat pump installed in 2015 in the U.S. has a seasonal coefficient of performance (COP) of 2.45 and this is projected to increase to 3.75 by 2030. See Navigant Consulting (2014) and Jadun, et al. (2017).

Figure 17 Transportation Sector Energy Demand by Final Energy Type



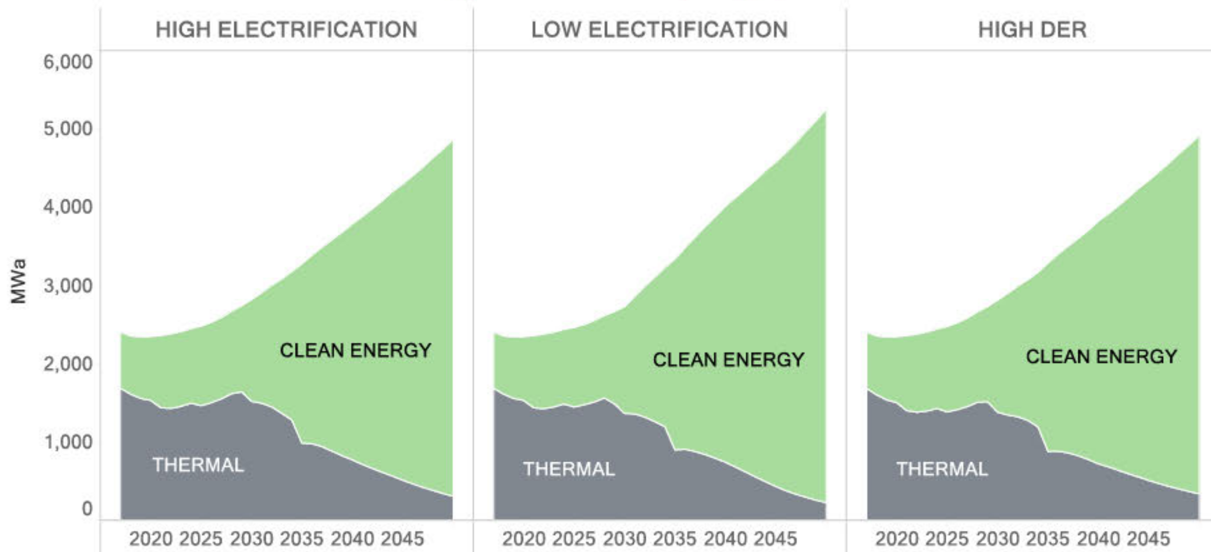
C. Energy Supply

1. Electricity

Figure 18 summarizes electricity supply through 2050, with generation from various resource types categorized as: (a) thermal, which includes generation from coal- and gas-fired resources, generic capacity and market purchases; and (b) clean energy, which includes generation from wind, solar, hydro and geothermal resources.[17] The figure shows that total electricity generation across all pathways grows rapidly, and total generation requirements in 2050 are more than double today's level. In all pathways, generation from non-emitting resources is more than 90 percent of the total and increases by 165 to 190 MWa per year between 2030 and 2050. Generation from thermal resources decreases significantly after 2035, and annual generation falls between 300 and 400 MWa by 2050.

[17] Our generation projections are not directly comparable to PGE's most recent IRP dispatch modeling due to the vintage of the load forecast provided for this study and the inclusion of direct access loads.

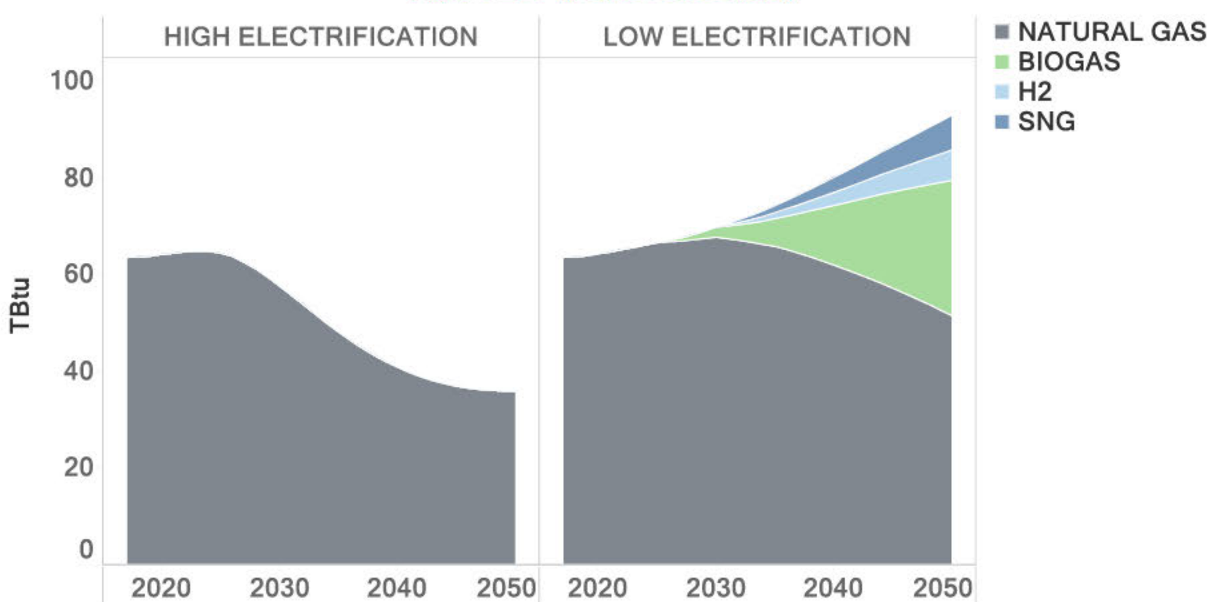
Figure 18 Electricity Supply



2. Pipeline Gas

Figure 19 compares pipeline gas supply for the High Electrification and Low Electrification pathways. In the High Electrification pathway, the pipeline gas supply remains entirely natural gas and total supply decreases by more than 40 percent relative to today due to electrification in buildings. Pipeline gas is decarbonized in the Low Electrification pathway with a combination of biogas and synthetic electric fuels, which reduces the share of natural gas to approximately 55 percent by 2050. Total gas supply increases by approximately 40 percent relative to today largely due to incremental gas demand from freight trucks with only a portion offset by more efficient use of pipeline gas in buildings.

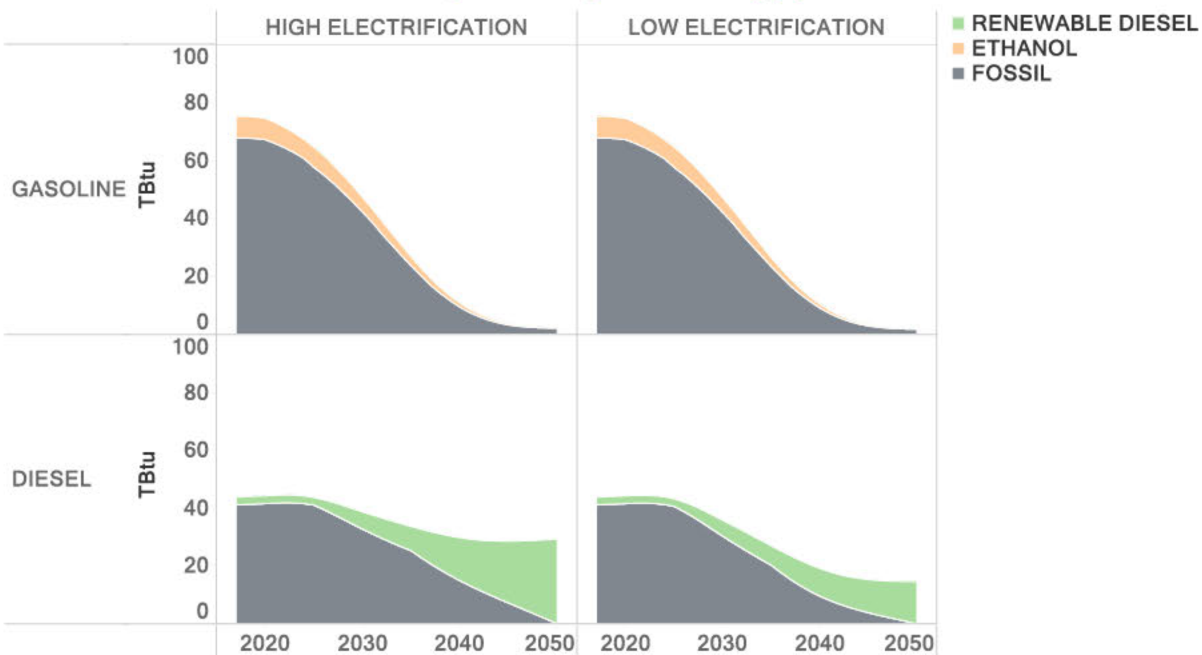
Figure 19 Pipeline Gas Supply



3. Liquid Fuels

Figure 20 summarizes the supply of today's two largest liquid fuels: gasoline and diesel. The supply of gasoline decreases by more than 95 percent by 2050 due to adoption of BEV, PHEV and HFCV vehicles in passenger transportation. Diesel remains a major fuel type in the High Electrification pathway, where half of freight trucks are hybrid diesel trucks. However, diesel supply transitions to 100 percent renewable diesel by 2050. The same supply transition occurs in the Low Electrification pathway, but total demand decreases by two-thirds by 2050 relative to today due to a shift from diesel trucks towards LNG and CNG freight trucks.

Figure 20 Liquid Fuels Supply



D. Energy-related CO_2 Emissions

Figure 21 and Figure 22 summarize energy-related CO_2 emissions by sector and energy type, respectively. The transportation sector's emissions, which is the largest source of emissions today, decrease by more than 90 percent across all pathways. This is the largest reduction by sector and total transportation emissions are less than the combined emissions from residential and commercial buildings by 2050. The transportation sector is primarily decarbonized through the following strategies: (1) electrification of passenger vehicles and freight trucks paired with very low-carbon electricity generation; and (2) decarbonization of liquid and gaseous fuels supplying the remaining fleet of freight trucks with bioenergy. The productive sector contains the largest remaining CO_2 emissions by 2050, and these are primarily from the direction combustion of fossil fuels, as opposed to emissions associated with electricity consumption. Most of the residual emissions in buildings are from combusting pipeline gas, and these are 50 percent higher in the Low Electrification pathway relative to the other pathways.

Figure 21 CO_2 Emissions by Sector

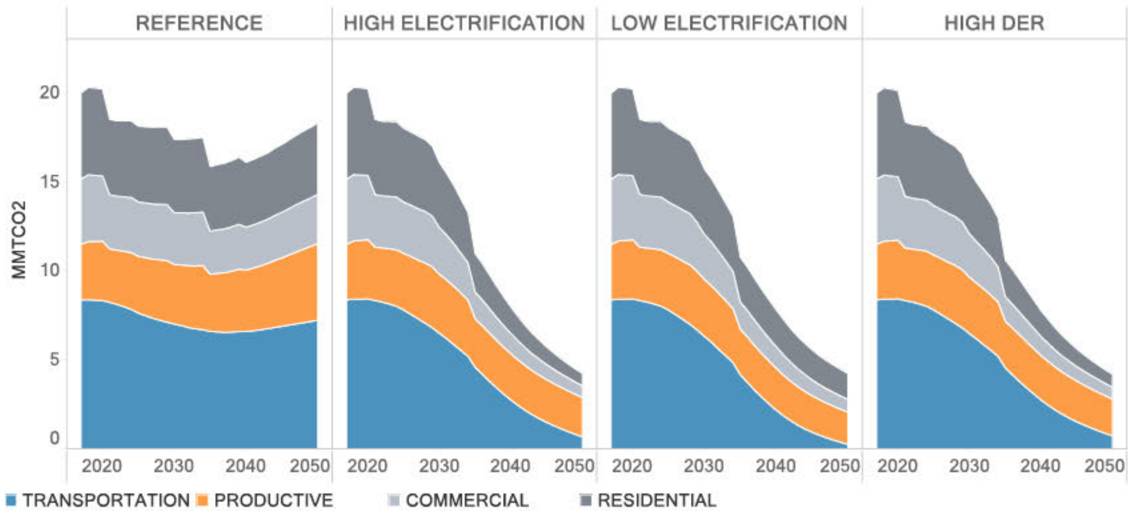


Figure 22 CO_2 Emissions by Energy Type

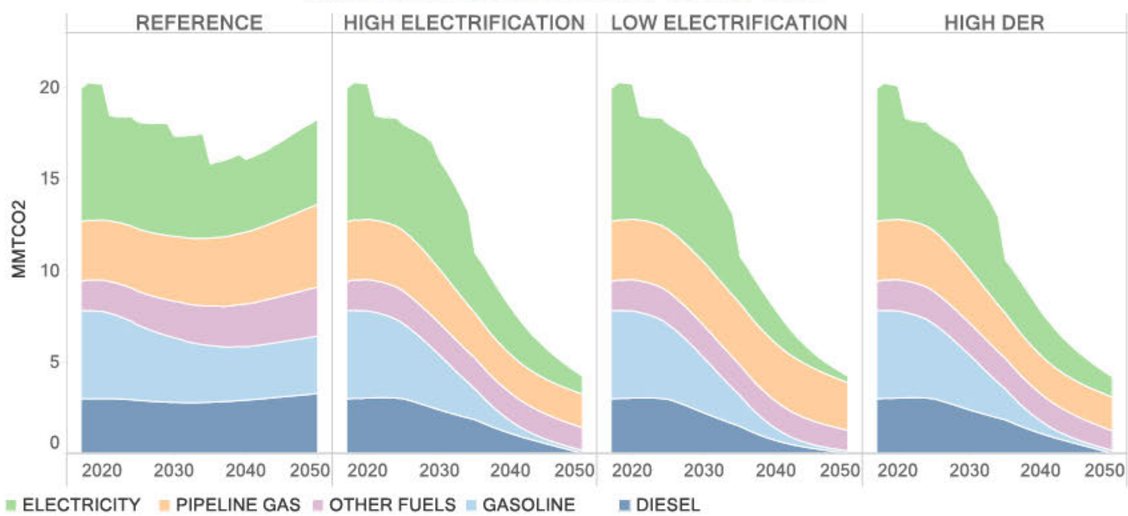
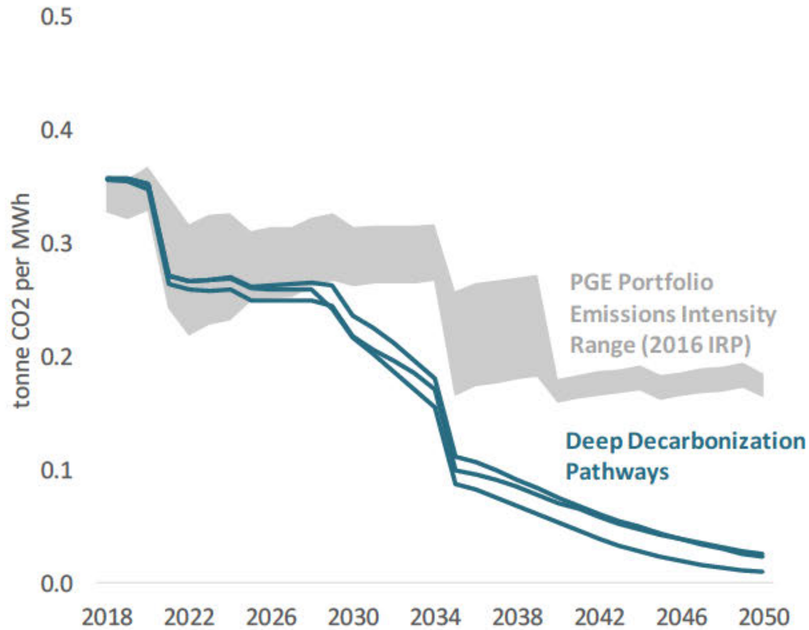


Figure 23 compares the emissions intensity of electricity generation from the three pathways against the range of PGE's portfolio from the 2016 IRP. Both projections decrease over time, with noticeable drops in 2020 and 2035 due to the assumed phase out of coal-fired electricity supply. The emissions intensity in the pathways scenarios begins to aggressively decrease beginning in the mid-2020s, and, relative to the minimum of the range, is at least 33 percent lower in 2035 and more than 85 percent lower by 2050. In 2050, the emissions intensity is below 0.03 tCO_2/MWh for all pathways, while the 2016 IRP ranges from 0.16 to 0.19 tCO_2/MWh.

Figure 23 Emissions Intensity of Electricity Generation



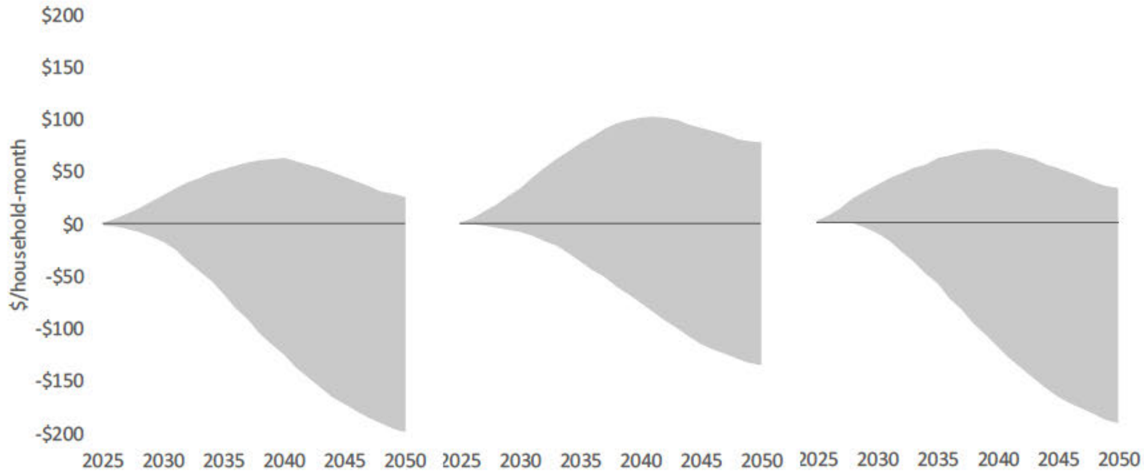
E. Energy System Costs

We measure the cost of transitioninig towards a low-carbon energy economy by comparing the incremental cost of investment in low-carbon and efficient equipment and infrastructure against the savings from avoiding fossil fuel purchases. This is calculated by taking the difference in energy system-related costs between a pathway scenario and the Reference Case. We exclude costs outside of the energy system, as well as benefits from avoiding climate change and air polution.

The annual, incremental cost for households is shown in Figure 24, which includes: (a) the annualized cost of appliances (e.g., high efficiency dishwasher); (b) the annualized cost associated with passenger transportation (e.g., electric vehicle); and (c) energy costs associated with using the equipment (e.g., gasoline for a vehicle and electricity for lighting). Given the challenge of projecting relative costs through a long study horizon (i.e., 2050), we show the results across a range of alternative fossil fuel price and end-use electric technology cost projections.[18] Year-to-year variations are due to: (a) the timing of investment needs; and (b) the assumed projections of technology costs and fuel prices. The range of uncertainties encompass both net cost increases and net cost decreases (savings) by 2050.

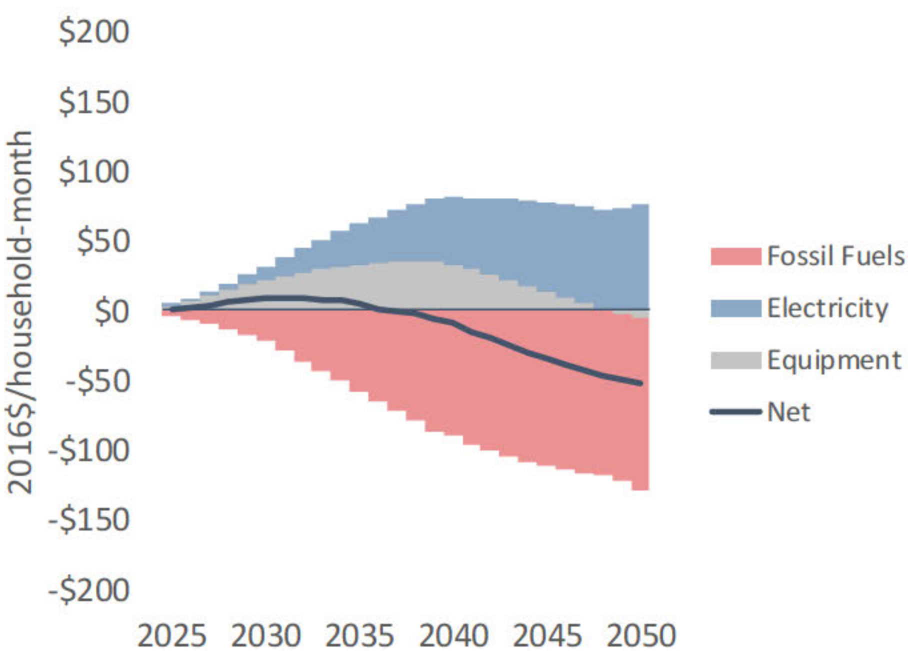
[18] Range of fossil fuel price projections are from the EIA's *Annual Energy Outlook 2017* and end-use electric technology cost projections are from NREL's *Electrification Futures Study*.

Figure 24 Range of Incremental Household Costs



Incremental household costs reflect the underlying changes in the energy system, such as: (a) increased spending on efficient end-use equipment (fixed costs); (b) increased spending on clean electricity infrastructure (fixed costs); and (c) decreased spending on fossil fuel costs (variable costs). Figure 25 illustrates how the structure of incremental household costs evolve over time for the High Electrification pathway under base fossil fuel price and end-use electric technology cost assumptions. Between 2025 and 2050, the average household spends additional money on equipment, such as an electric vehicle, air source heat pump and heat pump hot water heater, as well as additional money to power their equipment with clean electricity, including renewable power plants and transmission/distribution network upgrades. Meanwhile, households spend less money on fossil fuels, such as: (1) gasoline and diesel for their cars and trucks; and (2) natural gas for space and water heating.

Figure 25 Incremental Household Costs by Component: High Electrification Pathway

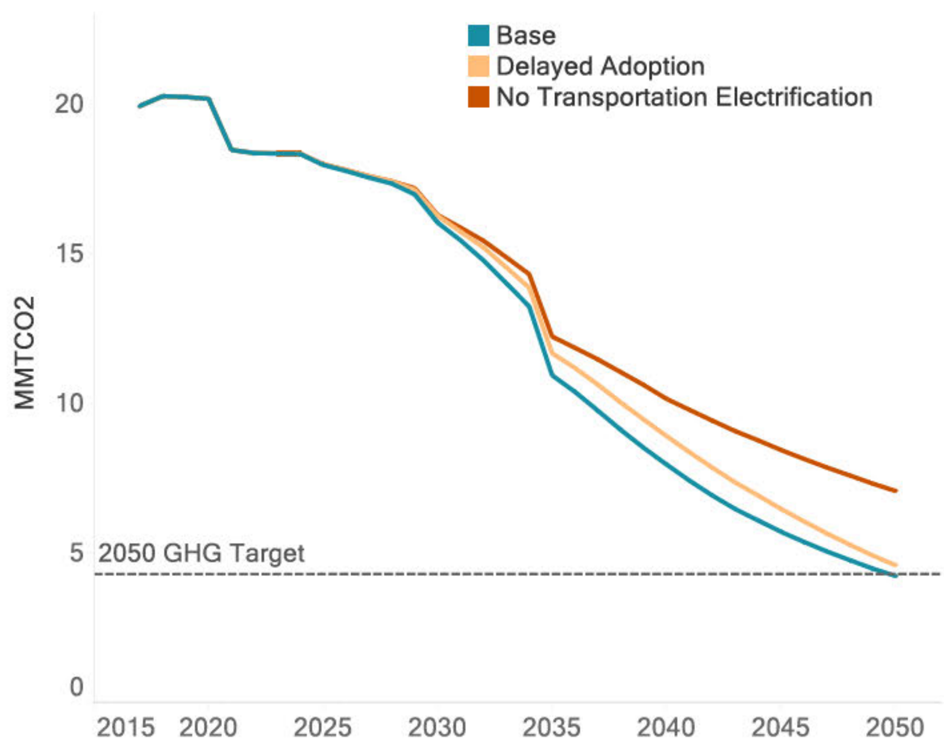


F. Transportation Electrification Sensitivity Analysis

Decarbonizing the transportation sector is essential to realizing economy-wide GHG reduction goals, and the pathways outlined above rely on passenger and freight transportation electrification. This requires aggressive consumer adoption by the mid-2030s for the fleet of vehicles on the road in 2050 to have the necessary low-carbon attributes. In the High Electrification pathway, 100 percent of light-duty vehicle sales are BEV or PHEV by 2035 and 50 percent of medium- and heavy-duty vehicle sales are BEV by 2035. To assess the importance of these aggressive transportation electrification strategies, we tested two sensitivities: (1) delay the assumed year of 100 percent BEV/PHEV adoption for light-duty vehicles from 2035 to 2050 ("Delayed Adoption"); and (2) remove all passenger and freight transportation electrification measures ("No Transportation Electrification").

Figure 26 shows the difference in CO_2 emissions between the High Electrification pathway ("Base") and the two sensitivities. The figure shows that delaying adoption of EVs in passenger transportation increases emissions in 2050 by 8 percent or 0.36 $MMTCO_2$, which results in the pathway no longer complying with the study's 2050 GHG target. This is because more than 10 percent of cars and trucks on the road in 2050 still consume petroleum rather than clean electricity as their fuel. CO_2 emissions increase by two-thirds without any transportation electrification (above 7 $MMTCO_2$) and the sensitivity does not achieve the emissions reductions necessary to meet the 2050 GHG target. We also note that the increase in emissions is partially mitigated through increased renewable diesel consumption by freight trucks (i.e., diesel freight trucks that transition to electric freight trucks in the base case now consume renewable diesel). However, the amount of bioenergy in this sensitivity exceeds the limit described in Section II.D, and, if strictly enforced, then emissions would be higher than shown here.

Figure 26 Energy-related CO_2 Emissions: Transportation Electrification Sensitivities



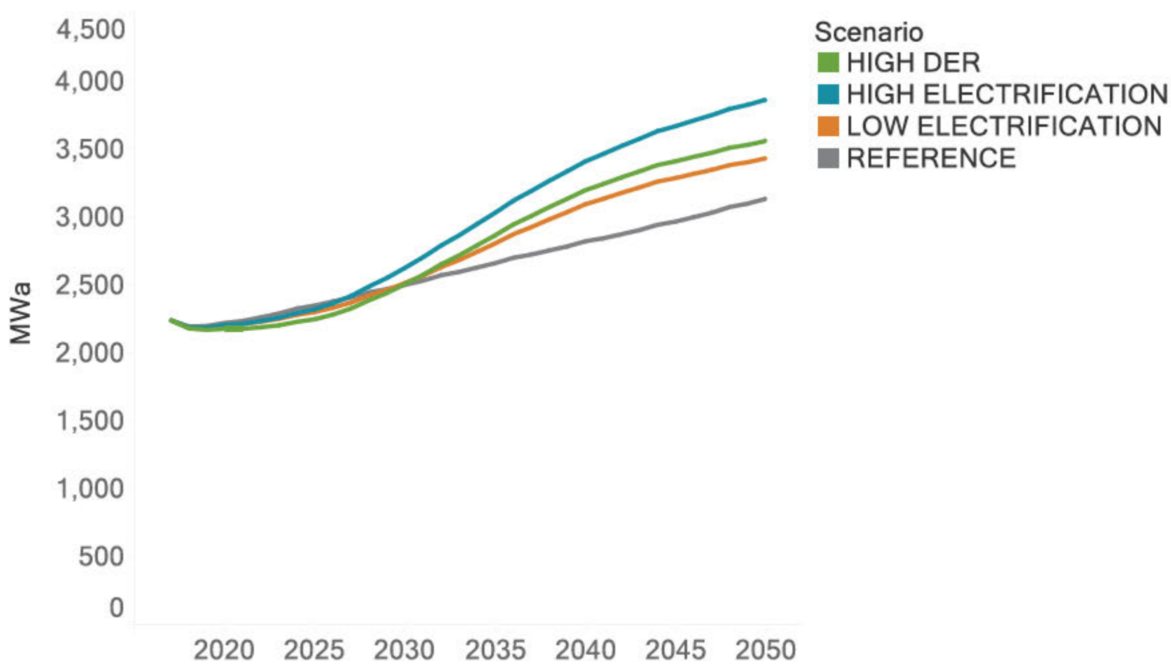
V. Results: Electricity System

This section summarizes results for the electricity system, including load, resources and hourly system operations. We also report the sensitivity of the results to variations in flexible end-use load, flexible electric fuel production, battery energy storage and pumped hydro storage assumptions.

A. Load

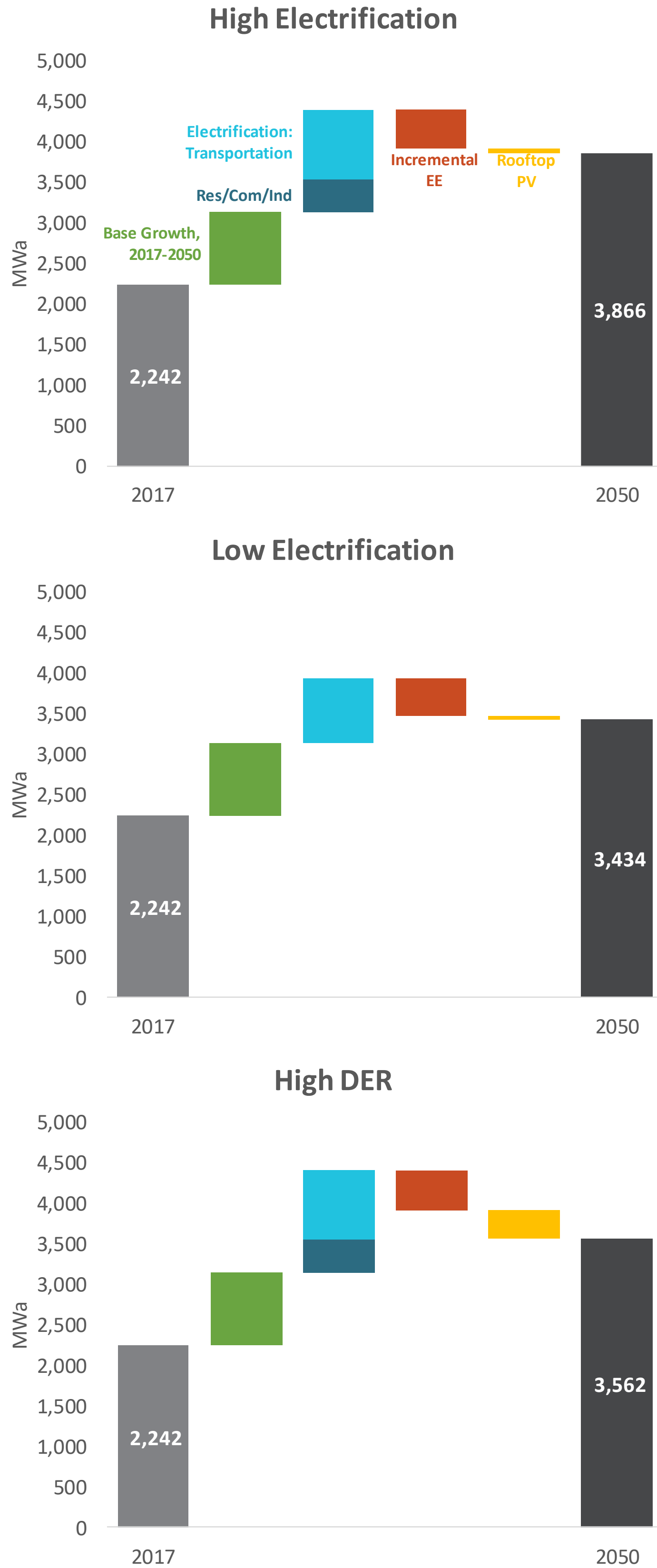
Figure 27 shows the trajectory of retail electricity sales for each scenario through 2050. In the long-run, retail sales in all pathways are higher than the Reference Case, and, as expected, the High Electrification pathway is the highest. Deployment of rooftop solar PV resources in the High DER pathway partially offsets end-use electrification measures, resulting in retail sales that are slightly above the Low Electrification pathway in 2050. Relative to today, retail sales increase by 50 to 70 percent by 2050.

Figure 27 Retail Electricity Sales



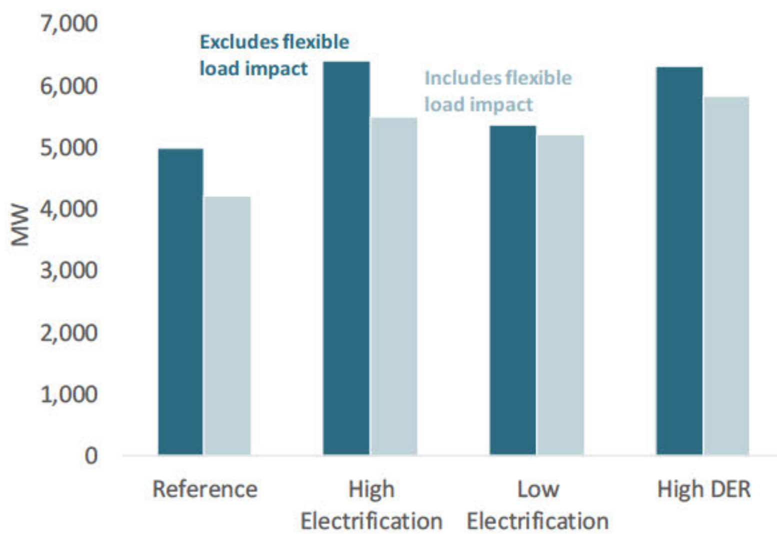
The components of the change in retail sales between 2017 and 2050 are shown in Figure 28, which separates: (a) baseline growth (i.e., growth that is embedded in the Reference Case); (b) electrification of buildings and industry; (c) transportation electrification; (d) incremental energy efficiency (EE measures beyond what's embedded in the Reference Case); and (e) rooftop solar PV generation. This figure highlights two key insights. First, transportation electrification is responsible for 50 to 65 percent of the net increase, as liquid fuels are replaced by electricity. Second, generation from rooftop solar PV has a smaller than expected *net* impact on retail sales. This is most apparent in the High DER scenario, where rooftop solar PV exceeds 2,500 MW (larger than today's average load). In this pathway, incremental electricity demand from end-use electrification still outweighs the directionally opposite impact from rooftop solar. This is a result of the lower-quality solar resource (i.e., low capacity factor) in PGE's service territory, and we would not expect similar conclusions to be drawn in geographies such as California or Arizona.

Figure 28 Evolution of Retail Electricity Sales, 2017-2050



We estimate the system peak load as the highest hourly load value from our simulations. As discussed in Section II.B, our hourly load (and resource) shapes reflect 2011 weather conditions, which means that the results we report here will not exactly match a 1-in-2 (weather-normalized) peak demand. Figure 29 plots the system peak load in 2050 in two ways. The first metric (in dark blue) represents "fixed demand" and excludes any impacts from load shifting, storage charge/discharge and flexible electric fuel production. The chart illustrates how widespread end-use electrification in the High Electrification and Higher DER pathways results in a system peak load of approximately 6,400 MW, which is about 1,400 MW higher than the Reference Case. Despite the proliferation of rooftop solar PV in the High DER pathway, the system peak load is nearly equivalent to the High Electrification pathway since it occurs during a winter morning before meaningful insolation. The second system peak load metric (in light blue) accounts for impacts from flexible end-use loads during the same hour, which moderates the impacts of electrification on peak loads.

Figure 29 2050 System Peak Load



B. Resources

1. Installed Capacity

Figure 30 shows the projection of installed capacity for thermal, generic capacity and renewable resources. Decarbonization of electricity generation and electrification requires renewable resource additions that far exceeds additions included in the Reference Case. The installed capacity of wind, solar, geothermal and hydro resources in the pathways is more than 2x the Reference Case quantity by 2050 and includes: (a) 5,100 to 5,900 MW of onshore wind in the Pacific Northwest; (b) 1,700 to 1,900 MW of onshore wind in Montana; and (c) 3,600 to 5,200 MW of utility-scale solar PV in central Oregon.[19] Rooftop solar PV in the High DER scenario reduces the amount of transmission-connected renewable generation, but its generation portfolio still requires utility-scale additions to reduce the carbon

[19] For context, NREL estimates technical potential of onshore wind resources in Oregon and Washington of approximately 45,480 MW and Black & Veatch estimates approximately 56,150 MW of utility-scale solar PV in Oregon alone. See Lopez et al. (2012) and Black & Veatch (2015).

intensity of electricity generation to levels consistent with the study's carbon budget. The Low Electrification pathway contains the highest installed capacity due to the amount of electricity required to serve synthetic electric fuel production loads.

Figure 30 Installed Generating Capacity

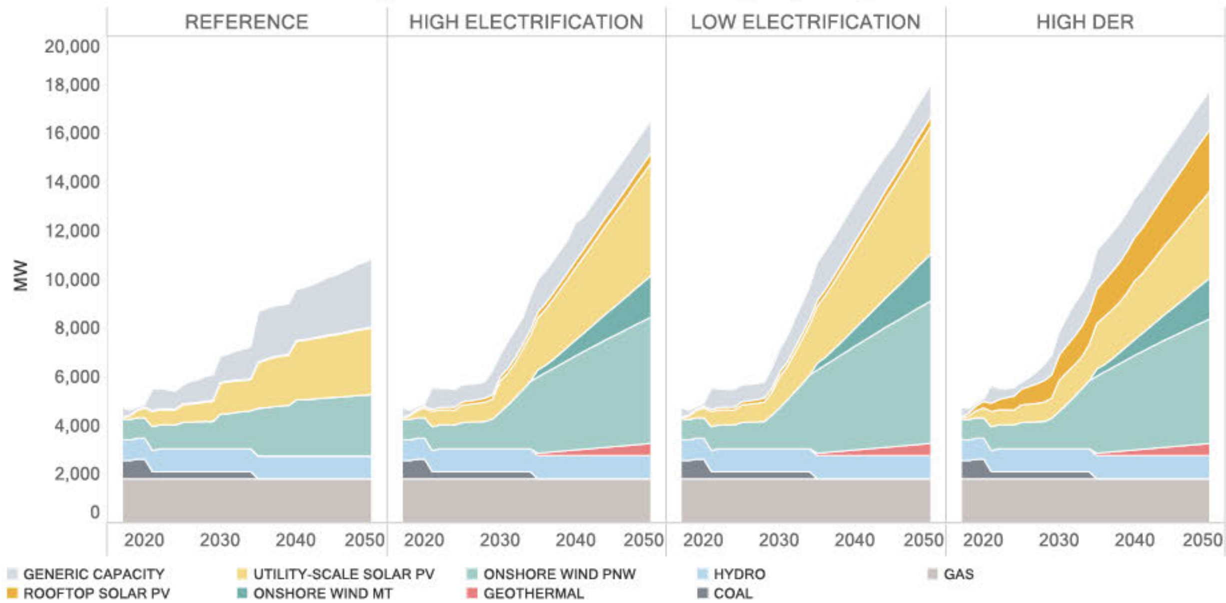
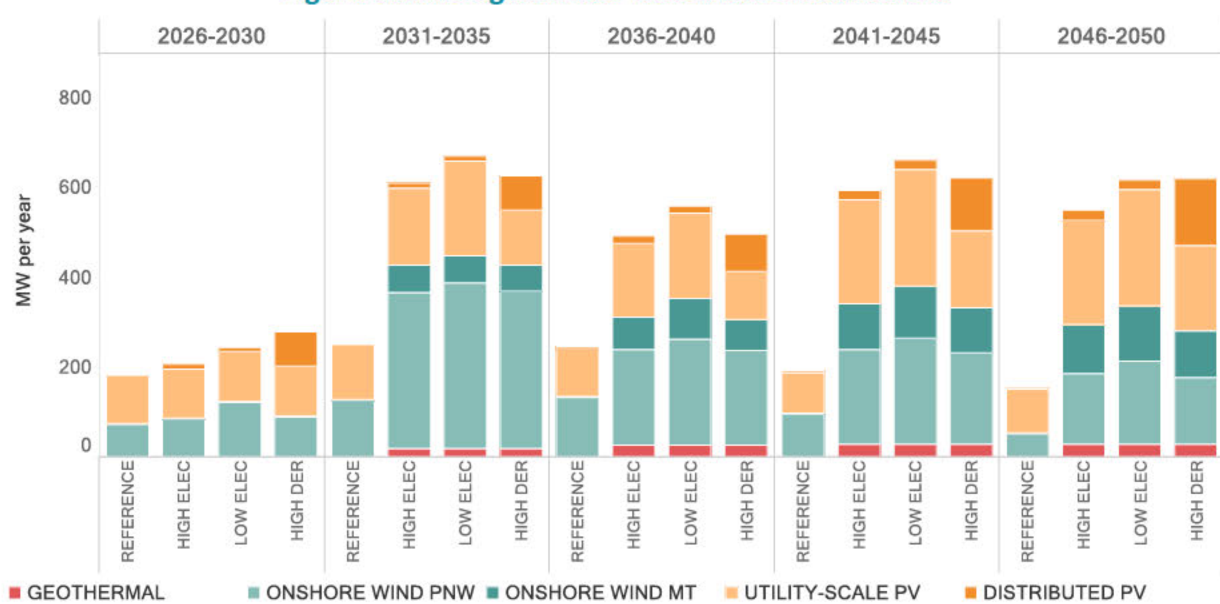


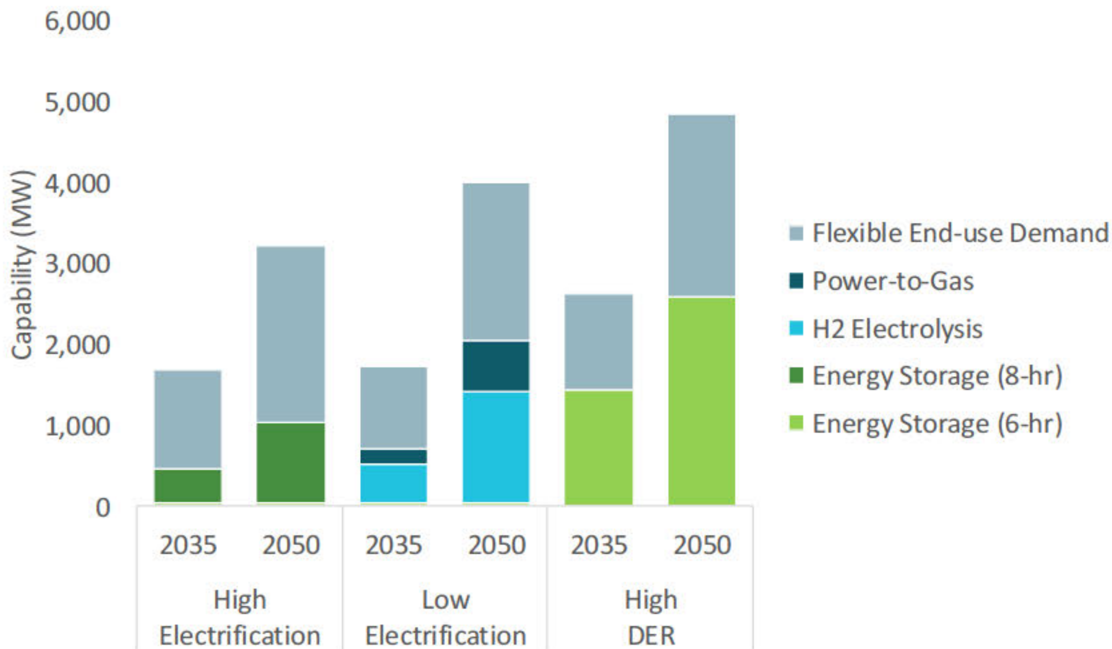
Figure 31 shows the annual average capacity additions of renewable resources, which are approximately 600 MW per year between 2030 and 2050 for the pathways scenarios. Annual renewable additions for the pathways scenarios are more than 2.0x Reference Case levels during the 2030s and more than 3.0x during the 2040s. For context, the amount of new onshore wind capacity beginning in 2030 is the equivalent to one to two Tucannon River (267 MW) wind power plants installed each year.

Figure 31 Average Annual Renewable Installations



The high penetrations of must-run renewable resources added across the pathways necessitate resources to balance electricity supply and demand. In addition to traditional sources of flexibility, such as hydro and thermal, the pathways incorporate a variety of new balancing resources to mitigate curtailment of renewable generation. Figure 32 shows the type and quantity of balancing resources incorporated in each pathway, including: (a) energy storage, which is differentiated between 6- and 8-hr duration; (b) hydrogen electrolysis facilities; (c) power-to-gas facilities; and (d) flexible end-use demand, which is estimated as the maximum hourly load shift in each year. The High Electrification and High DER pathways rely on a combination of flexible end-use demand and energy storage, while the Low Electrification pathway incorporates more than 2,000 MW of hydrogen electrolysis and P2G facilities by 2050 to consume excess renewable electricity generation and produce decarbonized pipeline gas. The High Electrification pathways contains the lowest quantity of physical / central-station balancing resources (i.e., 1000 MW of 8-hr energy storage) and relies on end-use loads to shift energy. The ability of these balancing fleets to minimize curtailment is further discussed in Section C.4 below.

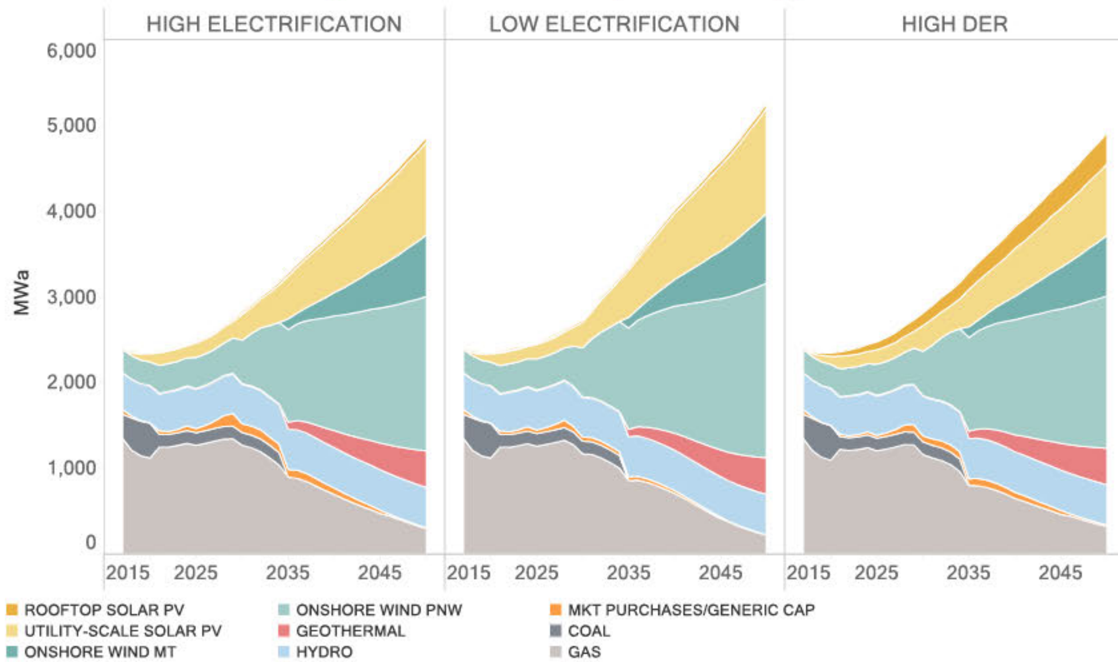
Figure 32 Balancing Resources



2. Generation

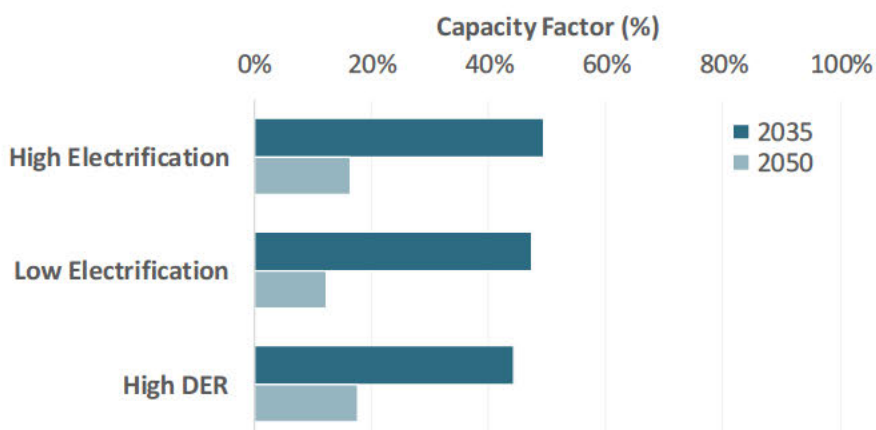
The overall generation mix by resource type for each pathway is shown in Figure 33. Annual generation more than doubles from approximately 2,400 MWa today to between 4,900 and 5,300 MWa by 2050. Carbon-free generation is more than 90 percent of the total by 2050, including an approximate mix of: (a) 50 percent onshore wind in the Pacific Northwest and Montana; (b) 25 percent solar PV, including both utility-scale in central Oregon and rooftop PV resources located within PGE's service territory; (c) 9 percent hydro; and (d) 8 percent geothermal. Due to the increased penetrations of renewable resources, thermal generation decreases significantly over time and is between 4 to 7 percent of total generation by 2050.

Figure 33 Generation by Resource Type



The capacity factor of PGE's existing gas-fired resource fleet is shown in Figure 34. The figure highlights how the growth in intermittent renewable generation between 2035 and 2050 decreases the utilization of these dispatchable resources from approximately 50 percent in 2035 to below 20 percent in 2050, a decrease of approximately 30 percentage points. The highly renewable power systems modeled in this study still require dispatchable resources to maintain reliability, and the gas-fired resource fleet, along with a variety of other balancing resources, have the characteristics to avoid unserved energy. The results here do indicate a shift in the role of these resources, particularly for combined cycle plants, from an energy to a capacity resource.

Figure 34 Gas-fired Resource Fleet Capacity Factor



C. System Operations

1. Load and Net Load

We compare the distribution of hourly load and net load in 2050 for each scenario as histograms in Figure 35, and report summary statistics in Table 11. These two metrics are estimated as follows: (a) load includes inflexible, transmission-level load less behind-the-meter generation (e.g., rooftop solar PV); and (b) net load is load minus non-dispatchable generation, including onshore wind, utility-scale solar PV, geothermal and run-of-river hydro resources. Both exclude the impact of flexible loads and resources.

The load distributions show the expected impacts of electrification, with the High Electrification and High DER distributions shifting towards the right. The net load distributions provide a more meaningful benchmark in terms of assessing the amount of dispatchable capacity needed to reliably meet demand and the flexibility required to avoid curtailment. The net load distribution for the Reference Case, which includes a 50% RPS in 2050, shows net load below zero for 5 percent of hours in the year. The pathways scenarios, which include at least twice as many non-dispatchable renewables, have net load distributions that are much flatter than the Reference Case and frequently below zero.

The High Electrification net load distribution is below zero in approximately 50 percent of hours per year, and the minimum net load experienced is approximately -8,000 MW. During these hours, flexible resources are needed to consume additional load (e.g., energy storage charge) to avoid curtailment. The maximum net load is approximately 5,000 MW, which is about 4 percent higher than the Reference Case's maximum net load. The High DER pathway shows similar net load distribution results due to comparable levels of electrification and renewables.

Relative to the other pathways, the Low Electrification pathway's net load is distributed further left (i.e., more hours with negative net load). Net load is below zero for 64 percent of hours in the year and nearly reaches -10,000 MW in a single hour. This shape is due to different load and resource characteristics, including: (a) lower levels of end-use electrification; and (b) higher levels of inflexible renewable generation. Flexible hydrogen electrolysis and power-to-gas facilities consume load during these negative net load hours to produce low-carbon electric fuels and avoid curtailment.

Figure 35 Distribution of Hourly Load and Net Load in 2050

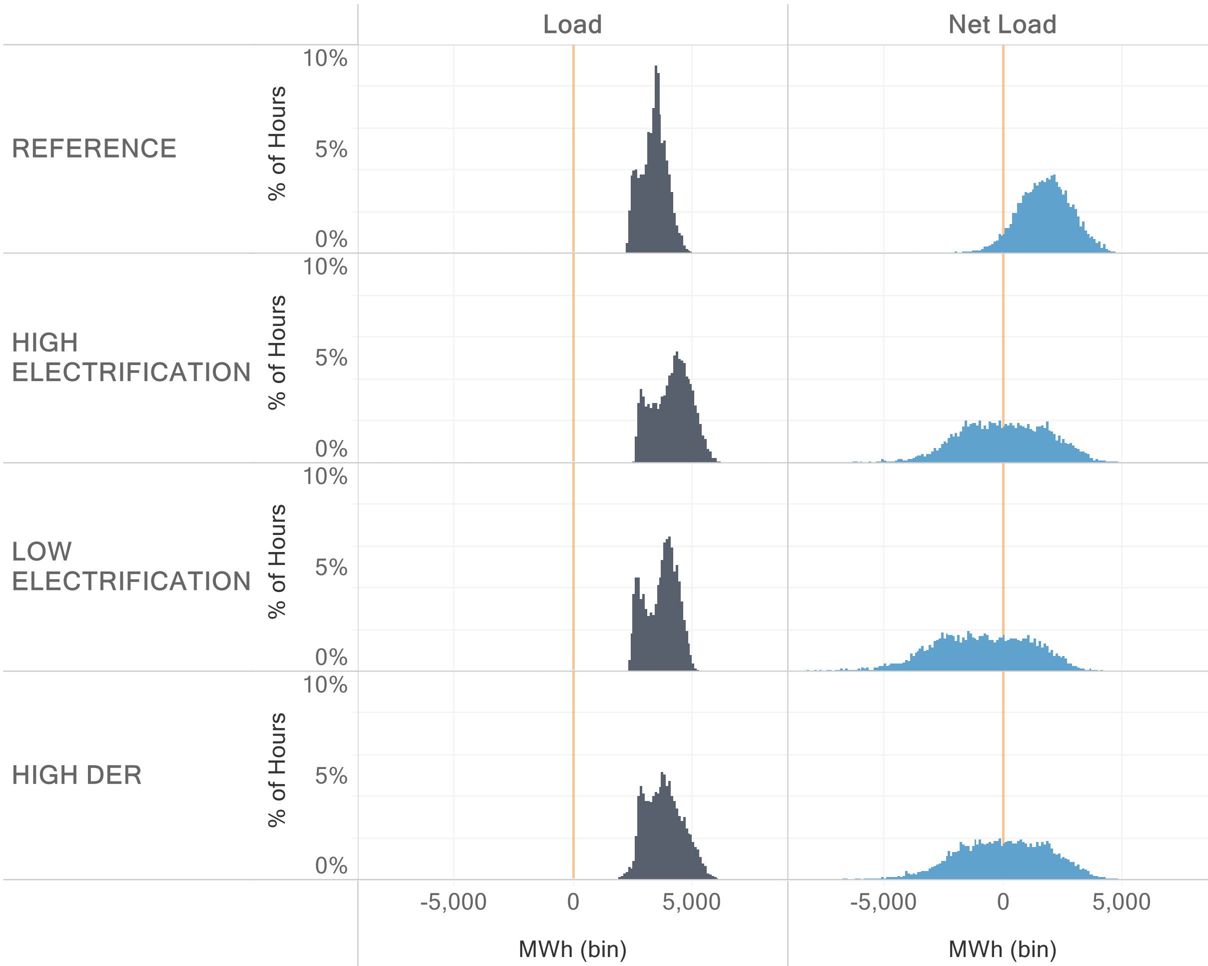


Table 11 Statistics for Hourly Load and Net Load in 2050

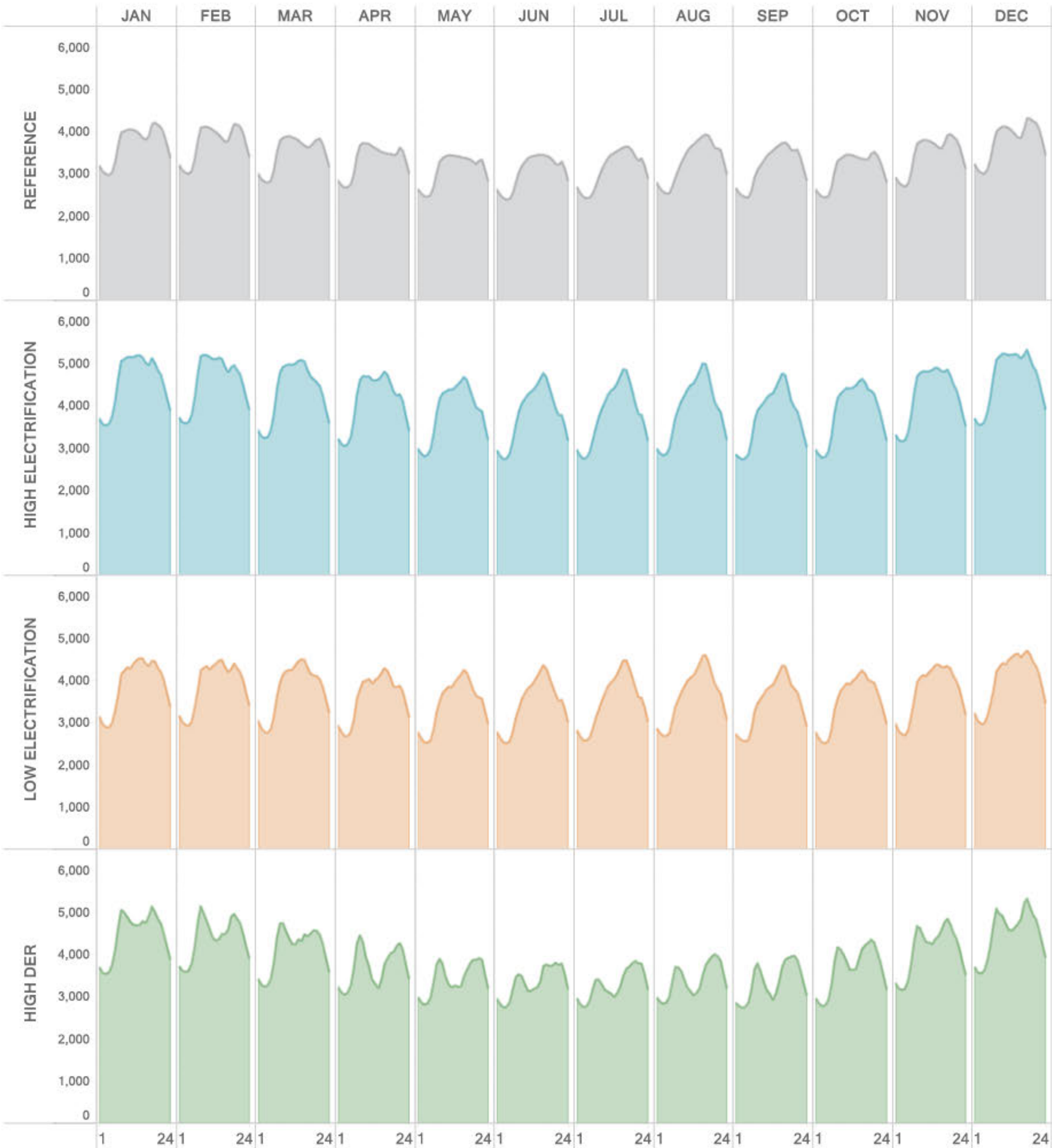
Scenario	Load		Net Load			
	Max	Min	Max	Min	Frequency below 0 MW	
	MW	MW	MW	MW	hrs	% of hrs
Reference	4,972	2,191	4,758	-2,392	457	5%
High Electrification	6,391	2,555	4,957	-7,942	4,346	50%
Low Electrification	5,351	2,273	4,261	-9,996	5,600	64%
High DER	6,310	1,920	4,961	-8,574	4,337	50%

2. Hourly System Load Shape

The average load by month and hour in 2050 for each scenario is summarized in Figure 36. The figure shows the system load shape prior to accounting for flexible loads and illustrates how the nature of electricity demand is affected by rooftop solar PV and varying levels of electrification.[20] The High Electrification pathway shows higher winter loads relative to the Reference Case primarily due to the electrification of space heating, but large new loads are also present in non-winter months largely due to transportation electrification. These non-heating related load increases are also present in the Low Electrification pathway and are most apparent in the early evening hours when most EV charging is assumed to take place. Although the High DER pathway contains the same electrification measures as the High Electrification pathway, the proliferation of rooftop solar PV changes both the daily and seasonal characteristics of electricity demand, including: (a) steep upward and downward ramps during the daylight hours across all months; and (b) large differences in daily energy requirements between winter and spring/summer months.

[20] The load shapes for the pathways also reflect high levels of electric energy efficiency.

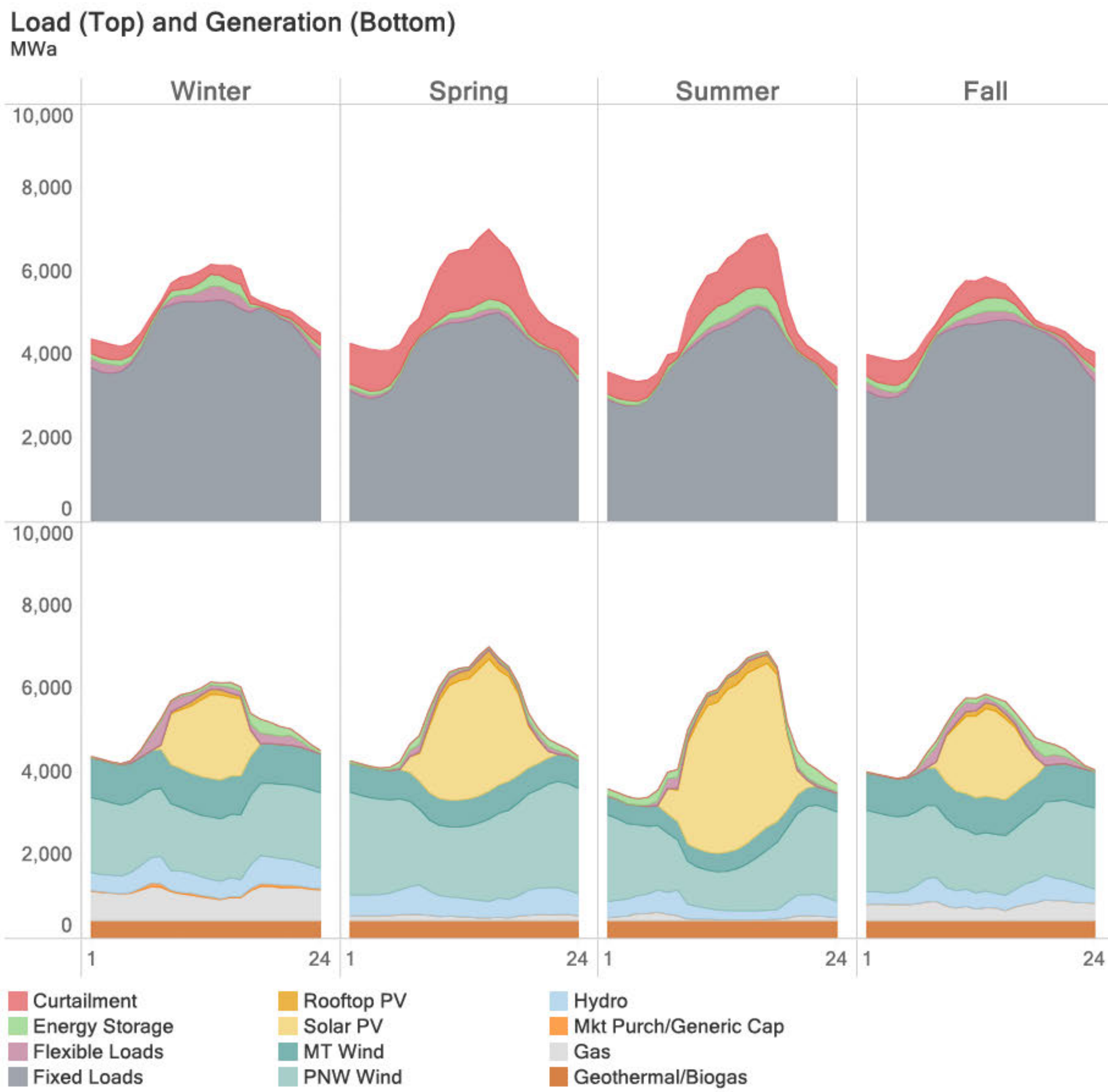
Figure 36 System Load Shape: Month-Hour Average in 2050



3. Month-Hour Electricity Dispatch

Figure 37 through Figure 39 show hourly average dispatch profiles by season for each pathway, where the top panel contains all sources of load and the bottom panel contains all sources of generation.[21] The figures illustrate how electricity supply and demand technologies combine across hours and seasons, and the operating profiles of flexible balancing resources.

Figure 37 Electricity Dispatch: High Electrification Pathway, 2050



[21] Seasons defined as: (a) winter includes December through February; (b) spring includes March through June; (c) summer includes July through September; and (d) fall includes October through November.

Figure 38 Electricity Dispatch: Low Electrification Pathway, 2050

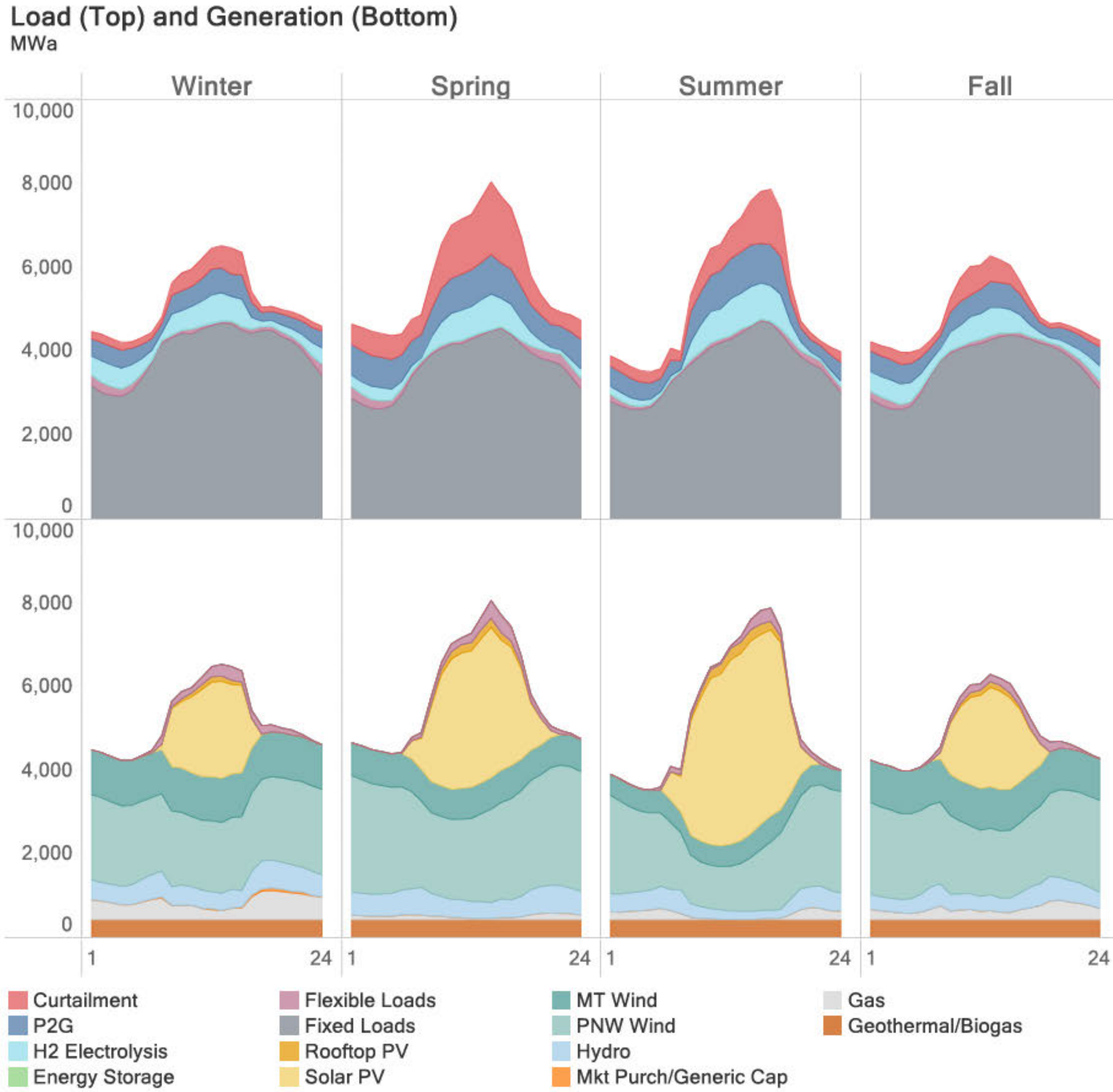
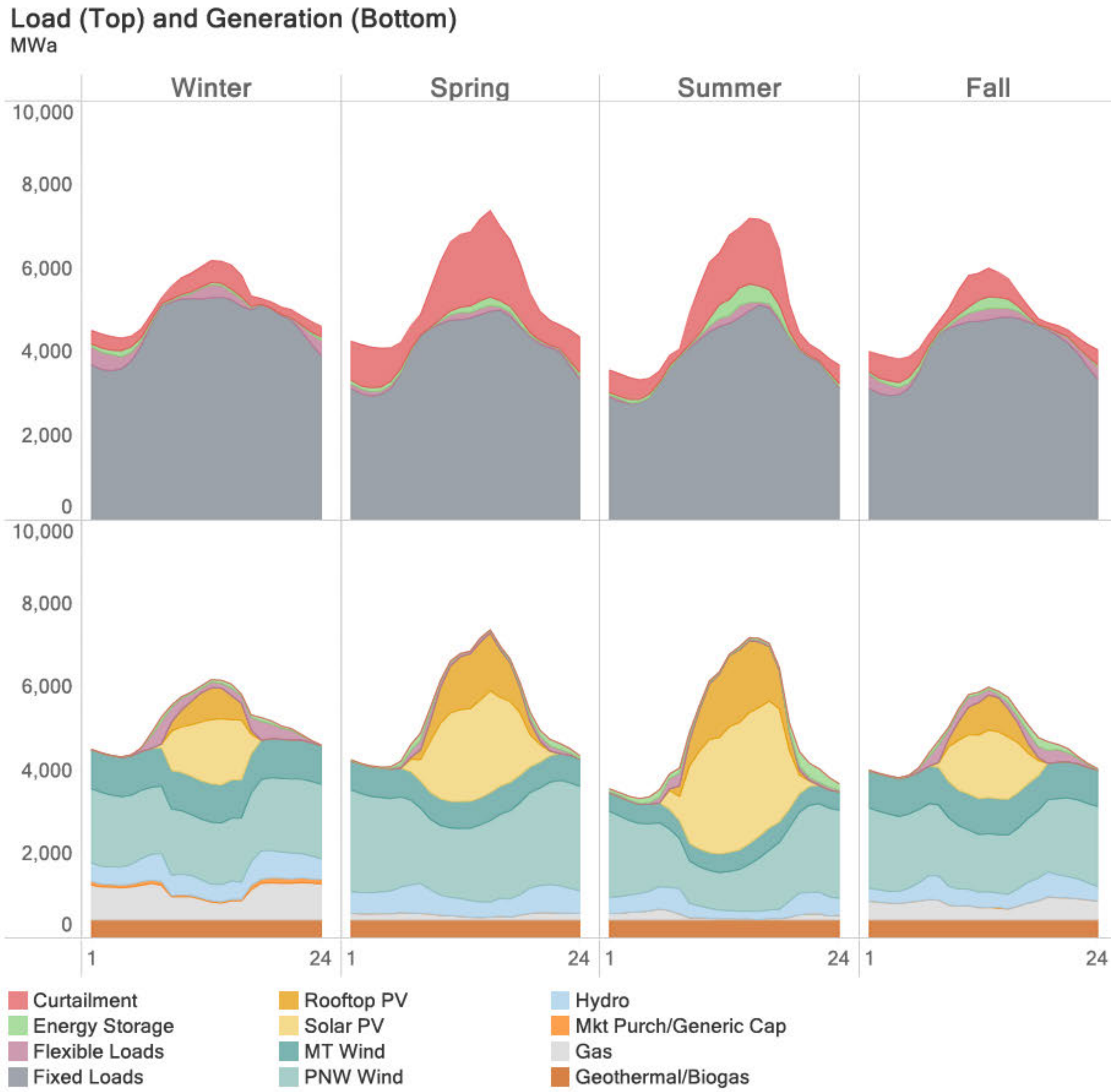


Figure 39 Electricity Dispatch: High Distributed Energy Resources Pathway, 2050



4. Curtailment

Curtailment of renewable generation occurs during periods where: (1) must-run generation exceeds load, resulting in an initial negative net load signal; and (2) balancing resources are unable to shift surplus energy to hours with energy deficits (i.e., positive net load signal). Figure 40 plots annual curtailment for each scenario and shows that curtailment does not become prevalent until the 2035 timeframe. As the share of inflexible, renewable generation increases above 85 percent by 2050, curtailment increases exponentially even after the impacts of balancing resource are accounted for.

Figure 40 Annual Curtailment

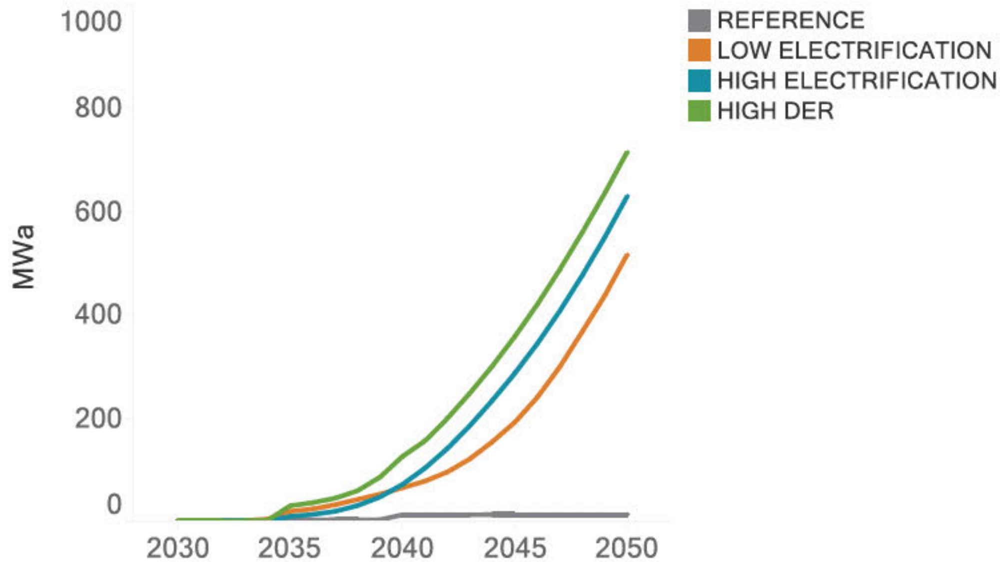


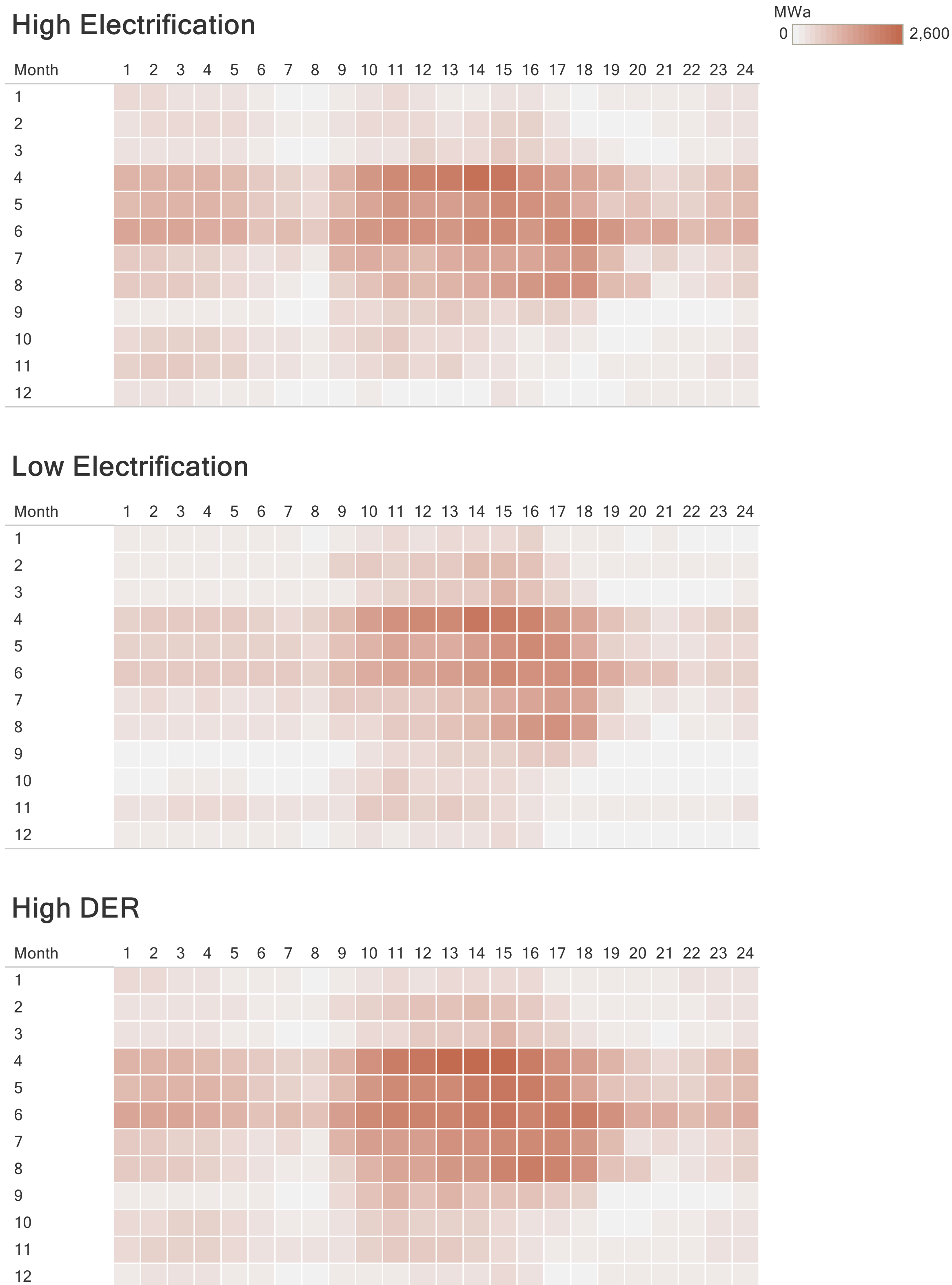
Table 12 summarizes several curtailment metrics for 2035 and 2050, including: (a) the amount of energy curtailed in average megawatts; (b) curtailment normalized as a percentage of available renewable energy; (c) maximum hourly observation; and (d) frequency, expressed in percentage of hours in a year. Curtailed generation is less than 2 percent of available renewable energy in 2035 across all pathways and increases to between 11 and 17 percent by 2050. Curtailment is experienced between 40 and 55 percent of hours in 2050, which is a decrease from the number of hours with negative net load (see Table 11) and reaches a maximum depth between 7,600 and 8,700 MW in a single hour. We explore the impact of alternative demand- and supply-side balancing resource assumptions on curtailment in the following section.

Table 12 Curtailment Metrics for 2035 and 2050

Scenario	Energy		Percent of Available RE		Hourly Maximum		Frequency	
	2035 MWa	2050 MWa	2035 %	2050 %	2035 MW	2050 MW	2035 % hours	2050 % hours
Reference	2	13	0.2%	0.8%	966	2,048	1%	3%
High Electrification	9	630	0.5%	15.0%	2,146	8,032	2%	39%
Low Electrification	19	517	0.9%	11.1%	2,378	7,597	4%	53%
High DER	30	716	1.5%	16.9%	3,121	8,663	5%	46%

The average amount of curtailment for each month and hour in 2050 is depicted as a heat map in Figure 41, with a darker red highlighting more extreme curtailment. The heat maps show that curtailment is concentrated during spring months when loads are low and renewable generation is high. Curtailment experienced during April through June makes up approximately half of annual curtailment, while only 11 to 13 percent occurs between December through February. Although most curtailment is concentrated during day-light hours, it is still experienced during the night-time and is up to 30 percent of the total in the High Electrification pathway.

Figure 41 Curtailment Heat Map for 2050



D. Sensitivity Analyses

In this section, we evaluate the sensitivity of our modeling results to alternative assumptions about the availability of demand- and supply-side resource flexibility. These sensitivities explore the impacts of alternative assumptions from the High Electrification pathway, including: (a) varying the availability of flexible end-use load; (b) including flexible electric fuel production (i.e., electrolysis); and (c) varying the quantity and type of energy storage. These sensitivities are summarized below.

Flexible End-use Load. In the High Electrification pathway, we assume a percentage of electric load is flexible in key end-uses: (a) 75 percent of light-duty vehicle electric load is flexible by 2050; (b) 75 percent of residential and commercial water heating electric load is flexible by 2050; and (c) 50 percent of electric load is flexible for residential space conditioning, residential clothes washing and drying and commercial space heating. We tested three cases designed to assess the importance of end-use flexibility: (a) no flexible end-use load; (b) only flexibility from electric vehicles; and (c) only flexibility from water heaters.

Flexible Electric Fuel Production. The results presented in the prior section highlight the seasonal imbalance between electricity supply and demand in a highly renewable power system. The base assumption in the High Electrification pathway is that energy storage and flexible end-use loads are the principal balancing resources. To assess the impact of long-term or seasonal storage, we conducted a sensitivity analysis where hydrogen produced from electrolysis facilities provides 3.5 percent of pipeline gas supply, which translates into more than 300 MW of electrolysis facilities.

Variation in Energy Storage. Varying the quantity of energy storage affects the ability of a power system to successful integrate inflexible renewable electricity generation. In the High Electrification pathway, the base assumption is that 1,000 MW of 8-hour energy storage is in-service by 2050. In this sensitivity, we assess the implications of: (a) increasing the quantity of 8-hour energy storage from 1,000 MW to 1,500 MW; and (b) assuming 500 MW of 24-hour pumped hydro storage (PHS) by 2050.

Table 13 summaries the results of our sensitivity analyses for 2050, which are shown as differences relative to the High Electrification pathway. We report changes in: (a) curtailment, in terms of average megawatts and percent difference; and (b) energy system CO_2 emissions, in million metric tonnes and percent difference. Removing flexibility from end-use loads increases curtailment by nearly 10 percent and emissions increase by 5 percent due to higher thermal generation, which results in the sensitivity exceeding the study's 2050 carbon budget. Including flexibility from electric vehicles and hot water heaters dampens the effect of losing other end-use flexibility, with curtailment and emissions rising modestly. The sheer volume of electric load from electric vehicles (more than 15 percent of total load in 2050) relative to water heaters allows for better curtailment and emissions outcomes. Electrolysis facilities and pumped hydro, both long-duration storage, show similar outcomes with curtailment decreasing by more than 10 percent. In contrast, increasing the quantity of 8-hour storage produces less than half the reductions in curtailment. The results of these sensitivity analyses highlight the importance of flexible end-use loads for integrating renewable generation, as well as the effectiveness of long-duration energy storage to reduce curtailment and address seasonal energy imbalances that occur in highly renewable electricity systems.

Table 13 Flexibility Sensitivity Analysis Results (Relative to Base Assumptions)

Sensitivity	Curtailment (MWa)	Curtailment (%)	Emissions ($MMTCO_2$)	Emissions (%)
Flexible End-Use Load				
None	+54	+9%	+0.21	+5%
Flexible EV Load Only	+14	+2%	+0.05	+1%
Flexible WH Load Only	+36	+6%	+0.14	+3%
Flexible Electric Fuel Production				
Add Electrolysis Facilities	-78	-12%	-0.08	-2%
Energy Storage				
Increase 8-hr energy storage	-31	-5%	-0.07	-2%
Add 24-hr PHS	-68	-11%	-0.15	-4%

Notes: values for 2050 and relative to High Electrification pathway base assumptions.

VI. Summary

We find that deep decarbonization of the PGE service territory's energy economy is possible and can be achieved using a variety of energy technologies and mitigation strategies. Our analysis of multiple pathways shows that they depend on a set of three pillars that are consistent with many studies examining deep decarbonization in the U.S. and abroad, including: (1) energy efficiency; (2) decarbonizing electricity generation; and (3) increasing the share of electricity and electric fuels. All three pillars are required and pursuing only one is insufficient.

The level of change to the energy system identified in this study is transformational and cannot be achieved with incremental improvements to energy supply and demand. In order to facilitate a pathway to 2050, both consumers and producers will need to participate to ensure that energy infrastructure is low-carbon and efficient. Although 2050 is more than three decades away, a successful transition to a low-carbon economy requires timely planning to account for: (a) the pace of consumer adoption; and (b) the fact that energy infrastructure is long-lasting and takes years to plan for. Despite the ambitious transformation of the energy system, the changes would not entail major lifestyle changes, but the structure of a household's energy bill will shift from fossil fuel expenditures to investments in technology.

Economy-wide decarbonization will profoundly change the way electricity systems are operated and planned for. In terms of power system operations, balancing electricity supply and demand becomes more challenging as inflexible, variable renewable generation becomes the principal source of supply. For example, the three pathways show renewable generation exceeding load in approximately half of all hours by 2050. This operational paradigm necessitates a transition to new forms of balancing resources to integrate renewables and avoid curtailment. New sources of flexibility, including energy storage and flexible demand, can complement traditional sources of flexibility, such as hydro and thermal resources. This also provides an opportunity for PGE's customers to facilitate renewable integration by playing a more active role through smart EV charging and water heating (among others), which expands upon traditional demand response programs.

Electricity system planning in the context of deep decarbonization will need to account for broad changes across the energy economy to ensure that infrastructure with the right attributes is available to come online in a timely fashion. For example, future resource adequacy analyses will need to address changes in: (a) overall load requirements; (b) the shape of hourly load; (c) the level of inflexible renewable resources; and (d) penetration of flexible demand. In addition, the scale of resource additions identified in this study exceeds historical levels due to: (1) reducing the carbon intensity of electricity generation to nearly zero; and (2) increased generation requirements from electrification and/or producing fuels from electricity (i.e., H2 and SNG). As a result, the installed capacity of renewables is substantially higher than what's anticipated in any current planning proceedings and is more than double the quantity we would expect under current RPS policy. If regulators pursue policies commensurate with the emissions reductions evaluated here, then the results of this study highlight a number of considerations that could be investigated in PGE's integrated resource planning efforts to ensure that near-term actions are consistent with a long-term decarbonized future.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Production

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Bradley Jenkins
Stefan Cristea

July 9, 2021

Table of Contents

I. Introduction

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

A. My name is Bradley Jenkins. My position at PGE is Vice President, Utility Operations. I am responsible for all aspects of PGE's line operations and generation plant operations.

My name is Stefan Cristea. My position at PGE is Sr. Regulatory Analyst in the Rates and Regulatory Affairs department.

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 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 2022 test year O&M expenses related to PGE's generating plant operations as compared to actual 2020 O&M expenses.

Q. How is the remainder of your testimony organized?

A. Our testimony has five additional sections. In Section II, we discuss PGE's generation resources and their recent performance. In Section III, we discuss our forecast of 2022 test year generation O&M expenses. Section IV provides details regarding generation plants Major Maintenance Accruals (MMAs) and PGE's proposal to create a one-time MMA to allow recovery of costs associated with regulatory driven major maintenance, scheduled to occur in 2022 on the Kelso-Beaver (KB) gas pipeline. We then summarize our request in this filing in Section V and provide our qualifications in Section VI.

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 2022 test year?

A. Yes. Confidential PGE Exhibit 701 lists PGE's generating resources and their expected average energy output as modeled under normal conditions for PGE's initial 2022 Net Variable Power Cost (NVPC) forecast.

Q. Have PGE's long-term power supply resources changed significantly since the 2019 general rate case (GRC) filed in Docket No. UE 335 (UE 335)?

A. Yes. Pursuant to PGE's 2016 Integrated Resource Plan (IRP) Revised Renewable Action Plan (acknowledged through Commission Order No. 18-044) and the subsequent request for proposals, PGE added a new qualifying renewable resource, the Wheatridge Renewable Energy Facility (Wheatridge) to its generation portfolio. Wheatridge is a 300 MW wind generation facility, a 50MW solar facility, and a 30MW 4-hour duration energy storage facility located in Morrow County, Oregon. 100 MW of the wind generation facility is owned by PGE, while the remaining project output is being sold to PGE under two separate power purchase agreements (PPAs). The Commission approved PGE's request to recover the revenue requirement associated with the PGE-owned portion of Wheatridge in Order Nos. 20-279 and 20-321 in Docket No. UE 370. The wind component of Wheatridge was placed in service in Q4, 2020.[1]

[1] The 200MW subject to PPA achieved commercial operation on November 25, 2020 and the 100 MW PGE-owned portion was placed in service on December 7, 2020. The solar-battery component is expected to come online at the end of 2021.

Q. Are there any other significant changes to PGE's long-term power supply resources since the 2019 GRC?

A. Yes. There are two additional changes to PGE's supply resources: 1) PGE ceased operations at Boardman in October 2020; and 2) PGE expects that the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes) will exercise their contractual option to increase their ownership share at Pelton-Round Butte (PRB) at the end of 2021. While PRB's contribution to PGE's resource portfolio would not change for 2022, PGE's ownership of the facility would change from a current share of 66.67 percent to a 50.01 percent share.

Q. Please provide some background regarding the Boardman plant shut down.

A. PGE ceased coal operations at Boardman in October 2020, pursuant to Commission Order No. 10-457 issued in PGE's 2009 Integrated Resource Plan (Docket No. LC 48). Several options were evaluated during the 2009 IRP process. The decision to cease coal operations at Boardman in 2020 was made due to the Oregon Regional Haze Plan and Oregon Utility Mercury Rule setting forth additional pollution control requirements for Boardman. These regulations required PGE to examine the risks and benefits of making substantial investments in new emissions controls against the risks and benefits of ceasing plant operations and replacing Boardman with alternative energy sources. PGE's final recommendation was to cease Boardman coal operations at the end of 2020, a recommendation that was acknowledged by the Commission.

Q. Please explain why PGE's ownership share of PRB is likely to change at the end of 2021.

A. Pursuant to the PRB long-term global settlement and compensation agreement effective April 12, 2000, the Tribes had by no later than July 1, 2021, to provide formal notice of their intent to exercise their purchase option to increase ownership in the PRB facility from 33.33

percent to 49.99 percent, effective December 31, 2021. As such, just prior to PGE's 2022 GRC filing, the Tribes have formally notified PGE of their intention to exercise this option, thereby reducing PGE's PRB share starting in 2022 and implicitly, the O&M costs forecast in 2022.

Q. Is PGE currently performing major upgrades to any generation facility?

A. Yes. PGE is currently repowering the Faraday Hydro Facility on the Clackamas River.

Q. Please describe the original Faraday Hydro Facility.

A. The original Faraday Hydro Facility on the Clackamas River, constructed in 1907, consisted of a gravity dam, intake, tunnel, canal, forebay with spillway and unit intakes, penstocks, and a powerhouse with five vintage turbines (Units 1 through 5) and supporting mechanical and electrical systems. A new intake, penstock, and powerhouse with one turbine (Unit 6) was added in 1958.

Q. Please describe the Faraday upgrade work.

A. The Faraday Repower Project will replace PGE's original Faraday Hydro Plant (i.e., Units 1 through 5) on the Clackamas River. The new powerhouse will consist of two higher-efficiency turbines (Faraday Units 7 and 8) housed in a reinforced concrete structure with new flood protection systems and will result in increased plant reliability and efficiency. Unit 6 is still in good condition and no upgrade is necessary.

Q. What is the total expected capital cost of the Faraday Repower Project?

A. The total expected capital cost of the Faraday Repower Project, including Allowance for Funds Used During Construction, is $119.4 million.

Q. Why is the Faraday Repower Project necessary?

A. Faraday Hydro Units 1 through 5 were housed in an un-reinforced masonry building, which was seismically unfit and subject to flooding, requiring significant investment to continue safe and reliable operation. The facility had outlived its original design life, did not meet current structural code, and required increasing O&M costs. The new plant will optimize generation potential for the remaining license period (i.e., until 2055) and provide a modern plant with a 40-plus year design life.

Q. Why is it important to complete the Faraday Repower Project at this time and what value does it provide to customers?

A. As previously described in Docket No. UE 391, PGE Exhibit 100, the resource capacity stack in the Northwest Power Pool (NWPP) and CAISO regions has changed significantly in the last two decades. In the latter part of the 2000s and the 2010s, increasing amounts of renewable solar and wind energy were added to the resource stack while inefficient yet dispatchable gas plants and coal plants were retired. This shift in the resource stack is causing a regional capacity shortage in addition to significant energy market price volatility. The Faraday Repowering Project will provide PGE with continued plant reliability as well as non-emitting and firm capacity that will support PGE's capacity needs and decarbonization goals for the benefit of customers. Additionally, the Faraday Repowering Project supports a diverse resource portfolio that enables flexible operations and will result in incremental hydro generation eligible for Production Tax Credits that will provide a benefit to customers through a reduction to PGE's net variable power costs.

Q. When does PGE expect to finalize the upgrade work?

A. PGE expects Faraday Units 7 and 8 to be placed in service in March 2022.

B. Plant Performance

Q. What are PGE's goals for generating plant O&M?

A. Our primary goals for plant-related activities are to manage our generating plants in a safe, reliable, and economic manner, while maintaining compliance with all local, state, and federal laws, regulations, permits, licenses, and environmental standards. We achieve these goals by implementing prudent and timely maintenance practices, establishing effective safety and reliability initiatives, and making the necessary investments in our plants.

Q. How did PGE's thermal plants perform in 2020?

A. In 2020, PGE's thermal plants continued to perform well and maintained a relatively high availability. Overall thermal generation in 2020 was slightly lower than 2019 levels for some of our thermal plants due to major inspections, unplanned maintenance work, and the cessation of operations at Boardman in October 2020. In addition, the Boardman generating plant was economically displaced in the spring (March through June, 2020).

Confidential PGE Exhibit 702 provides historical 2018 through 2020 thermal plant availability.

Q. How does the 2022 expected generation for PGE's thermal resources compare to previous years?

A. Confidential PGE Exhibit 703 provides actual thermal generation for 2018, 2019, and 2020, and PGE's current 2022 forecast for each of our thermal resources. Adjusted to remove the impact of Boardman closing in 2020, thermal generation is expected to increase slightly in 2022 relative to 2020, primarily due to weather normalization and changes in the energy market fundamentals that result in an increased forecast dispatch of our gas thermal plants based on economics. PGE's 2022 initial NVPC filing in Docket No. UE 391 provides details regarding the MONET forecasted economic dispatch of PGE's thermal plants.[2]

[2] See PGE's 2022 initial NVPC filing here: https://edocs.puc.state.or.us/efdocs/HAA/haa94954.pdf

III. Generation Plant O&M

A. Generation Plant O&M Expenses

Q. What is your 2022 test year forecast of generation O&M expenses?

A. Our test year forecast of generation O&M expenses is approximately $109.8 million excluding Information Technology (IT) costs. After excluding Boardman-related costs from the base year, this represents a $6.7 million increase over 2020 actuals. Table 1 below summarizes these costs.

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

O&M Expenses	2020 Actuals	2022 Test Year	Delta	Annual % Change
PGE Labor	$35.2	$33.2	($2.0)	-2.9%
PGE Non-Labor	$48.9	$57.6	$8.7	8.5%
Major Maintenance Accrual	$11.3	$11.6	$0.3	1.1%
Plant Subtotal	$95.4	$102.4	$7.0	**3.6%**
Environmental Services	$7.7	$7.4	($0.3)	-1.7%
Sub-Total	$103.1	$109.8	**$6.7**	**3.2%**
Boardman Labor and Non-Labor	$11.9	$0.0	($11.9)	-100.0%
Information Technology (IT)	$15.1	$16.3	**$1.1**	3.7%
Total	**$130.1**	**$126.1**	**($4.0)**	-1.6%

** May not sum due to rounding*

Q. How is labor and non-labor generation O&M expected to change from 2020 actuals to the 2022 forecast?

A. We project labor-related generation O&M to decrease in 2022, as identified in the table above. Overall PGE labor is discussed in PGE Exhibit 300. We project non-labor-related plant generation O&M, including MMAs, to increase by approximately $9.0 million while costs associated with Environmental and Licensing Services to decrease by approximately $0.3 million in 2022. Section B below summarizes the major drivers of these variances.

Q. What do IT costs represent in Table 1?

A. IT costs here represent expenses that are directly assigned or allocated to generation and relate to PGE's efforts to develop, operate, and maintain our computer, information, cyber, 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 400.

B. Generation O&M Major Drivers

1. Non-Labor O&M Expenses

Q. What are the changes in non-labor plant O&M expenses?

A. The changes in non-labor plant O&M expenses from 2020 to 2022 are summarized in Table 2 below.

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

Operating Area	2018 Actuals	2019 Actuals	2020 Actuals	2021 Budget	2022 Forecast	Delta 2020 vs. 2022	Annual % Change
Colstrip Coal Plant	$12.4	$13.0	$18.7	$16.8	$17.1	($1.5)	-4.2%
Gas-Fired Plants	$16.1	$13.1	$9.2	$13.7	$15.4	$6.3	29.8%
Hydro Plants	$3.0	$4.2	$2.8	$2.6	$2.5	($0.3)	-5.7%
Wind Plants	$17.3	$19.5	$12.5	$15.6	$16.1	$3.6	13.6%
Major Maintenance Accrual	$14.3	$17.1	$11.3	$16.2	$11.6	$0.3	1.1%
General and Miscellaneous	$8.9	$9.2	$5.8	$7.7	$6.4	$0.7	5.5%
Sub-Total	**$72.1**	**$76.0**	**$60.2**	**$72.5**	**$69.1**	**$9.0**	**7.2%**
Environmental	$5.0	$4.6	$4.7	$4.9	$4.4	($0.3)	-3.1%
IT Expenses	$9.2	$13.8	$9.3	$9.6	$9.6	$0.3	1.7%
Boardman	$8.9	$7.2	$4.1	$0.0	$0.0	($4.1)	**-100.0%**
Total	**$95.2**	**$101.7**	**$78.3**	**$87.1**	**$83.1**	**$4.9**	**3.1%**

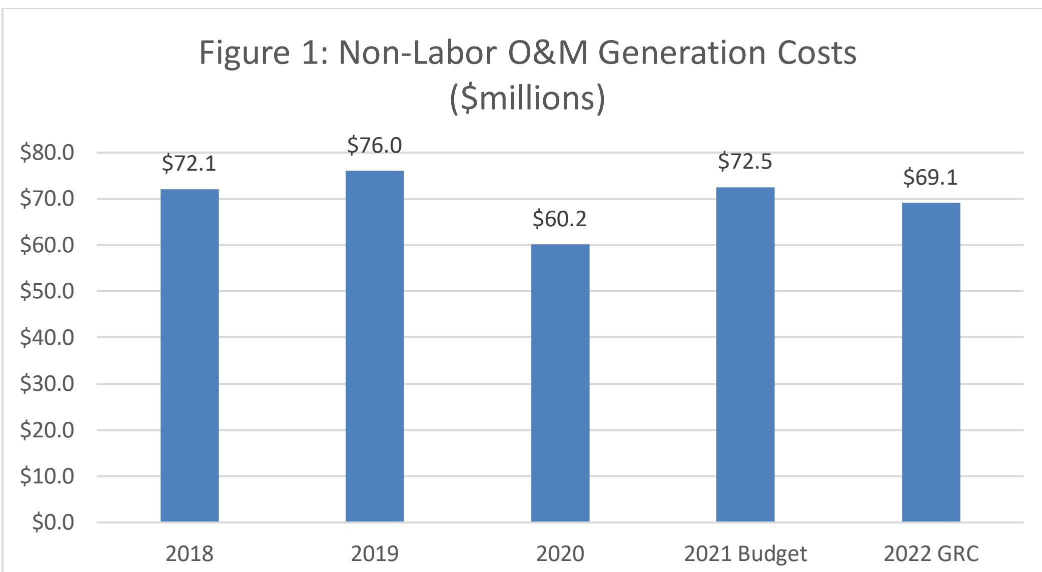
**May not sum due to rounding.*

Q. What is the main reason for the increase in non-labor plant generation O&M expenses in 2022 compared to 2020?

A. The increase in 2022 non-labor plant generation O&M forecast relative to 2020 actuals is primarily due to temporary measures taken by PGE in 2020 to address financial impacts and employee safety concerns due to the COVID-19 pandemic. To mitigate financial impacts and keep employees safe and also abide by the Oregon health directives and requirements related to the COVID-19 pandemic, PGE deferred certain maintenance activities resulting in reduced actual costs incurred in 2020 compared to the 2020 budget and prior years' actual costs.

Q. If 2020 was an abnormal year due to the COVID-19 pandemic, how does the 2022 non-labor plant generation O&M expenses compare to 2019 actual costs?

A. The 2022 forecast for non-labor plant generation O&M costs is lower than 2018 and 2019 actual costs, after adjusting for Boardman-related costs. Figure 1 below depicts the significant reduction in 2020 actual non-labor generation costs due to the COVID-19 pandemic impact. PGE's plant operations are expected to normalize in 2021 and 2022, as will the expected costs.



Q. What are the primary drivers for the changes in non-labor plant generation O&M expenses between 2020 actuals and 2022 forecast?

A. The primary drivers for the change in non-labor O&M expenses are:

1) Approximately $6.3 million increase related to gas plants' operations mainly due to temporary O&M reductions in 2020 to mitigate COVID-19 impacts, increased

maintenance work expected to occur in 2022, and ongoing site maintenance and site certificate costs being transferred from the Boardman facility to the Carty plant.

2) An increase of approximately $3.6 million due to non-labor O&M costs related to the addition of the Wheatridge wind facility to PGE's resource portfolio and a return to normal O&M spending for the Biglow Canyon and Tucannon River wind facilities.

3) An increase of approximately $0.7 million in general and miscellaneous O&M expenses.

4) Non-labor cost escalations.

Q. Did PGE apply any permanent efficiency reductions to generation O&M costs in 2020 that would continue into 2021 and 2022?

A. Yes, PGE applied permanent efficiency measures that reduced generation O&M costs in 2020 by approximately $2.5 million. For the 2021 budget and 2022 forecast PGE will continue to apply efficiency reductions to generation O&M of approximately $2.8 million.

Gas Plants

Q. What are the major drivers of the change in gas non-labor O&M expenses?

A. The $6.3 million increase in gas non-labor O&M expenses is driven primarily by:

1. A $1.5 million increase in the 2022 forecast due to the reversal of a temporary reduction in Beaver and Port Westward 1 (PW1) 2020 O&M generation costs implemented to mitigate financial, operational, and safety risks caused by the COVID-19 pandemic. This reduction is not sustainable and is related to maintenance activities and outside services that are needed in 2021 and 2022.

2. Approximately $2.3 million in costs associated with additional maintenance work at PW1, Beaver, Carty, and Coyote Springs as part of the plants' planned annual maintenance outages or needed for certain generation plant upgrades.
3. Approximately $2.0 million related to Boardman/Carty site maintenance, and water reservoir and air certificate permits.
4. Non-Labor costs escalations.

Q. Please provide examples of maintenance activities that were delayed from 2020 due to COVID-19 and need to be picked up in 2021 and 2022.

A. PGE delayed certain annual and ongoing maintenance activities at PW1 and Beaver that were deemed lower operational risk for 2020 plant availability and reliability. The maintenance work needs to be performed in 2021 and 2022, however, to maintain continued plant reliability:

- Port Westward 1 maintenance reductions of approximately $0.5 million to 2020 actuals:
  - The circulating water pump overhaul was delayed from 2020; and
  - The Static Frequency Converter and System Excitement System replacement due to end-of-life cycle was delayed from 2020.
- Beaver maintenance reductions of approximately $1.0 million:
  - Beaver Unit 3 maintenance overhaul was deferred from 2020 reducing 2020 costs by approximately $0.2 million; and
  - PGE temporarily reduced Beaver outside services, and materials and equipment expenses in 2020 by approximately $0.8 million.

Q. Please provide details regarding the incremental maintenance work at gas generation plants compared to 2020.

A. PGE will perform additional repair and maintenance work at the Beaver, PW1, and Coyote Springs plants. Some of the incremental maintenance work is listed below:

- Beaver:
  - Combustion Turbine repair work at Beaver Unit 6; and
  - Generator step-up transformer (GSU) upgrade at Beaver Units 5 and 6.
- Port Westward 1:
  - GSU upgrade;
  - PW1 Heat Recovery System Generator cleaning;
  - PW1 Reheat Stop valve overhaul based on a five-year rebuild cycle;
  - Oil leak repair and GSU testing; and
  - Gas flow meter calibration, breaker dynamic resistance testing, and evaporator meter replacement.
- Coyote Springs:
  - PGE will perform a major overhaul on the steam turbine and generator along with the main steam control valve that will result in additional O&M costs.

Q. Please provide more details regarding the site certificate costs and activities that are transferred from Boardman operations to Carty.

A. As described above, PGE will continue to incur costs of approximately $1.5 million associated with the Boardman-Carty site certificate permitting. These costs were previously charged to the Boardman operating unit and now are transferred to the Carty operating unit to ensure the site is compliant with Department of Environmental Quality regulations regarding the air and water reservoir permits. PGE submitted a Request for Amendment on March 13, 2020 for the Carty site certificate update related to the shutdown of Boardman.[3] The Amendment was issued on November 19, 2020.

Q. Please provide more details regarding the maintenance activities that are transferred from Boardman operations to Carty.

A. With the Boardman closure in 2020, there are several site-specific maintenance activities that will need to be performed for the Carty operating unit such as:

- Water intake structure maintenance: work entails adding traveling screens and screen wash pumps to remove debris from the reservoir water before it is sent to Carty.
- Water Reservoir Dam: work includes the reservoir dam inspections and planned maintenance on the overflow gate. Additional required maintenance could also include work on the seepage system that collects and removes water that permeates the earthen dam and any work on the reservoir water withdrawal pumps.
- Other work includes road maintenance, maintaining the Grassland Switchyard equipment and communication equipment, and ensuring security of the site.

Q. Are the costs associated with Carty site maintenance and certificates incremental to the 2022 forecast compared to 2020 actuals?

A. No. These costs appear as an increase in the 2022 forecast compared to 2020 actuals due to the removal of all costs previously associated with Boardman. However, they are ongoing costs that are now transferred to Carty operations.

[3] See application here: https://www.oregon.gov/energy/facilities-safety/facilities/Pages/CGS.aspx

Wind Plants

Q. What are the major drivers for the change in wind non-labor O&M expenses?

A. The $3.6 million increase in wind generation O&M costs is primarily driven by:

1. Approximately $2.3 million in additional O&M costs associated with the addition of the Wheatridge wind facility.
2. Approximately $0.9 million related to additional maintenance work at Tucannon and Biglow wind plants due to reduced maintenance activities and costs in 2020 that need to be incurred in 2021 and 2022 plus non-labor cost escalations.
3. Approximately $150 thousand in incremental expenses related to the Biglow Eagle Fatality Monitoring. In 2021 and 2022, PGE is required to perform an Environmental Fatality Study as part of the on-going work related to the Bald and Golden Eagle Protection Act Take Permit.[4]
4. Approximately $150 thousand in incremental expenses charged to Tucannon operating unit generation accounts that are related to ongoing site easement payments that were previously charged to transmission accounts.

Q. Does PGE have a Long-Term Service Agreement for Wheatridge?

A. Yes. PGE has executed an O&M agreement with NextEra Energy that provides for an annual fixed maintenance fee. This fee, which is currently being recovered through PGE's Schedule 122, is reflected in the O&M forecast for Wheatridge in this case.

[4] See https://www.fws.gov/pacific/migratorybirds/PDF/Biglow_docs/Biglow%20Final_EA%202020_0511.pdf for additional information.

General and Miscellaneous

Q. What are the major drivers for the change in general and miscellaneous non-labor O&M expenses?

A. The $0.7 million increase in 2022 non-labor general and miscellaneous generation costs is due primarily to reduced O&M activities performed in 2020 due to COVID-19 impacts. As reflected in Table 2 above, O&M costs related to general and miscellaneous operations are significantly lower in 2020 compared to prior years. If compared to 2018 or 2019 actual incurred costs, the 2022 O&M forecast for general and miscellaneous operations is lower by more than $2.5 million.

Major Maintenance Accruals (MMA)

Q. What are the major drivers for the change in MMA amounts?

A. We describe PGE's MMA accounts and their rationale in the next section. By way of summary, however, PGE's 2022 test year MMA expense charged to generation O&M is forecasted to increase by approximately $0.3 million compared to 2020 actual major maintenance expenses. However, as reflected in PGE Exhibit 704, 2022 forecasted MMA expense is approximately $1.1 million lower than the MMA amounts established in PGE's 2019 general rate case (Docket No. UE 335) that are currently in customer prices (MMA amounts are recorded in generation O&M accounts and in Other Revenue accounts). The decrease in 2022 MMA compared to the MMA amounts currently in customer prices is due to reductions in expected major maintenance expenses at PW1, PW2, and Colstrip, offset partially by increases to Carty and Coyote MMAs and PGE's proposal to create a one-time MMA to amortize certain 2022 O&M costs associated with the Kelso-Beaver (KB) pipeline.[5]

[5] See PGE Exhibit 700 work papers ("2022 GRC MMA Work Paper") for plant/project-specific MMA detailed calculations.

PGE Exhibit 704 provides MMA estimates for specific PGE thermal plants and the KB pipeline.

2. Labor O&M Expenses

Q. What is the change in labor O&M expenses from 2020 to 2022?

A. After adjusting for Boardman and IT expenses, labor O&M expenses are forecast to decrease by approximately $2.0 million in 2022 compared to 2020. The changes in generation labor O&M expenses from 2020 to 2022 are summarized in Table 3 below.

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

Operating Area	2020 Actuals	2021 Budget	2022 Forecast	Delta 2020 vs. 2022	Annual % Change
Colstrip Coal Plant	$0.0	$0.0	$0.0	($0.0)	-100.0%
Gas-Fired Plants	$13.6	$14.5	$14.9	$1.3	4.7%
Hydro Plants	$6.9	$7.3	$7.4	$0.6	4.1%
Wind Plants	$1.6	$1.5	$1.5	($0.0)	-0.2%
General and Miscellaneous	$13.2	$9.0	$9.3	($3.8)	-15.9%
Sub-Total	**$35.2**	**$32.3**	**$33.2**	**($2.0)**	**-2.9%**
Environmental	$3.0	$3.2	$3.0	$0.0	0.5%
IT Expenses	$5.9	$6.5	$6.7	$0.8	6.8%
Boardman	$7.8	($0.0)	($0.0)	($7.8)	**-100.0%**
Total	**$51.8**	**$42.0**	**$42.9**	**($8.9)**	**-9.0%**

**May not sum due to rounding.*

Q. What is the reduction in PGE generation labor costs if including Boardman actuals for 2020?

A. Boardman's closure results in a $7.8 million reduction in generation labor costs from 2020 to 2022, for a total labor reduction of approximately $8.9 million, inclusive of Boardman, from 2020 to 2022.

Q. Does PGE provide more details regarding 2022 projected labor costs?

A. Yes, PGE provides more details regarding overall 2022 projected labor costs in PGE Exhibit 300.

IV. Major Maintenance Accruals

Q. Please explain the 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 major maintenance accrual 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 benefitted. 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. How does the MMA benefit customers?

A. Normalizing the costs of maintenance has a number of customer benefits. As noted above, it smooths out the impact of "lumpy" maintenance costs on customer rates, provides better matching of customer costs and benefits from a timing perspective, and reduces the frequency of rate changes by eliminating the need to file nearly annual rate cases or deferred accounting applications to capture the significant increases or decreases in major maintenance costs.

Q. What items are currently included in the MMA?

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 Long-Term Service Agreements (LTSAs).[6] Listed below are examples of thermal generation 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. Is PGE proposing to include additional maintenance projects in the 2022 MMA calculation?

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

A. Yes. PGE is proposing to create an MMA to allow for the levelized recovery of costs associated with regulatory driven major maintenance that occurs once every ten years on the KB pipeline.

Q. Please describe the KB pipeline maintenance activity PGE proposes to include in the MMA.

A. PGE is required to perform pipeline integrity assessments every ten years to ensure compliance with regulations established by the Pipeline and Hazardous Materials Safety Administration. The pipeline integrity assessment involves using pipeline in-line inspection tools also referred as "smart pigs" (i.e., pipeline pigging), pressure testing, direct assessment, or other technology that can provide an equivalent understanding of the condition of the pipeline. PGE has scheduled the next assessment of the KB pipeline integrity to occur in 2022.

Q. What is the incremental cost associated with the KB pipeline pigging that PGE expects to incur in 2022?

A. PGE expects to incur approximately $0.72 million in incremental costs in 2022 for the KB pipeline pigging.

Q. What is PGE's specific proposal regarding the KB pipeline MMA?

A. PGE proposes to spread the KB pipeline maintenance costs over 5 years, which is consistent with the MMA methodology used for our gas thermal plants, explained below. This results in an increase to PGE's 2022 forecast of only $143 thousand, compared to a $0.72 million increase in the absence of an MMA.

Q. Why is PGE proposing to recover this cost through an MMA?

A. PGE is proposing to create a KB pipeline MMA to recover the above-described maintenance activities for the same reasons we created similar MMAs: to smooth the cost impacts of non-annual maintenance on customers.

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

A. PGE calculates the MMA for its gas thermal plants by forecasting the expected operational run of each thermal 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 2022 test year plant O&M costs.

A. For the 2022 test year, PGE will continue to have MMAs for Port Westward units 1 and 2, Coyote Springs, Carty, and Colstrip. In addition to these, PGE proposes adding an MMA for the KB pipeline as a one-time mechanism to smooth out over five years the maintenance costs expected to occur in the 2022 test year.

Q. What is the total MMA amount included in the 2022 test year plant O&M costs?

A. The total MMA amount included in the 2022 test year is approximately $16.3 million, inclusive of amounts recorded under Account 456, Other Revenues. As noted previously in Table 2, the 2022 test year MMA expense charged to generation O&M is forecasted to increase by approximately $0.3 million over 2020 actual major maintenance expenses. However, as reflected in PGE Exhibit 704, 2022 forecasted MMA expense, inclusive of MMA amounts recorded in Account 456, Other Revenues, is approximately $1.1 million lower than the MMA amounts currently in base rates.

V. Conclusion

Q. Please summarize your request for generation O&M in this filing.

A. We request that the Commission approve PGE's 2022 forecast of $126.1 million in generation O&M costs (including IT generation-related expenses). After excluding Boardman-related costs, the 2022 forecast represents a $7.9 million increase from 2020 costs due primarily to the reversal of temporary, COVID-19-related reductions in O&M costs and delays in maintenance activities, non-labor costs escalation, increases in IT costs, and updates to MMAs.

VI. Qualifications

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 Portland General Electric (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 3000 MWs of wind, solar, hydro, and thermal generation at 17 generation facilities, as well as the Trojan Independent Spent Fuel Storage Installation (ISFSI).

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 analyst for numerous PGE ratemaking, rulemaking, policy regulatory proceedings such as general rate cases (UE 319 and UE 335), annual power cost updates (UE 359 and UE 377), and Power cost adjustment mechanism filings (UE 346, UE 362, and UE 381). 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**
701C	PGE Generating Resource Summary
702C	PGE Thermal Plant Availability 2017-2020
703C	PGE Actual and Forecasted Thermal Generation
704	PGE Thermal Plant Major Maintenance Accruals

Exhibit 701 contains confidential information and is subject to General Protective Order 21-206.

Information provided in electronic format only.

Exhibit 702 contains confidential information and is subject to General Protective Order 21-206.

Information provided in electronic format only.

Exhibit 703 contains confidential information and is subject to General Protective Order 21-206.

Information provided in electronic format only.

Plant	2020 actuals	2021 Budget (per UE 335)	2022 FILE	2022 GRC revised	Variance (2020-2022 revised)	Annualized Variance (2019 GRC-2022 GRC)	Variance 2022 FILE vs 2022 Revised
Carty	5,493,019	5,492,364	5,503,300	6,850,948	1,357,929	1,358,584	1,347,648
Coyote	2,788,544	2,638,548	2,648,256	3,464,004	675,460	825,456	815,747
PW1	5,574,575	5,574,588	5,582,674	4,453,956	(1,120,619)	(1,120,632)	(1,128,717)
PW2	826,853	826,848	826,848	773,805	(53,049)	(53,043)	(53,043)
Colstrip	(129,151)	2,868,707	2,876,423	637,960	767,111	(2,230,747)	(2,238,463)
KB Pipeline Pigging	-	-	715,500	143,100	143,100	143,100	(572,400)
Total	**14,553,841**	**17,401,055**	**18,153,001**	**16,323,773**	**1,769,932**	**(1,077,282)**	**(1,829,228)**

PGE Accounts	2020 actuals	2021 Budget (per UE 335)	2022 FILE	2022 GRC revised	Variance (2020-2022 revised)	Annualized Variance (2019 GRC-2022 GRC)	Variance 2022 FILE vs 2022 Revised
MMAs in Account 4560002	3,252,694	1,158,780	4,763,984	4,763,984	1,511,290	3,605,204	-
MMAs in Generation O&M Accounts	11,301,147	16,242,275	13,389,016	11,559,788.35	258,642	(4,682,487)	**(1,829,228)**
check	-	-	-	-	(0)	-	(0)

PGE Exhibit 200 (Revenue Requirement) MMA		
2022 FILE	2022 REVISED	Adjustment
18,153,001	16,323,773	**(1,829,228)**

1. Total MMA amounts in Generation O&M Accounts and Account 4560002 (Other Revenue)

PGE Exhibit 700 (Generation O&M) MMA Adjustment[2]		
2022 FILE	2022 REVISED	Adjustment
13,389,016	11,559,788	**(1,829,228)**

2. Includes only Generation O&M Accounts

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Transmission & Distribution

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Larry Bekkedahl
Bradley Jenkins

July 9, 2021

Table of Contents

I. Introduction

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

A. My name is Larry Bekkedahl. I am the Senior Vice President of Advanced Energy Delivery. My qualifications appear at the end of PGE Exhibit 500.

My name is Bradley Jenkins. I am the Vice President of Utility Operations. I am responsible for all aspects of PGE's line operations and generation plant operations. 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 discuss Transmission and Distribution (T&D) capital expenditures from January 1, 2019 through April 2022 and incremental operations and maintenance (O&M) activities and costs for the 2022 test year. We specifically discuss the Integrated Operations Center (IOC), Advanced Distribution Management System (ADMS), Wildfire Mitigation (WM), Vegetation Management (VM), and Level III outage restoration costs.

These initiatives will allow PGE to be responsive to the major events of the past year including the COVID-19 pandemic, micro-bursts blowing down 500kV transmission towers, Labor Day Wildfire storms, and the February ice storm, in addition; implement a proactive approach to T&D system O&M, increasing reliability, resiliency, and flexibility needed to enable our customers' clean energy future with a more resilient and integrated grid. In addition to our discussion of these initiatives, we also discuss our request to modify the current Level III outage mechanism to allow for equitable recovery of prudently incurred service restoration costs.

Q. What are the primary goals for T&D?

A. PGE's primary goals for T&D investment and operations are to:

- Provide safe, affordable, secure, reliable, and resilient energy delivery services to our customers while meeting customer, state, and local decarbonization goals;
- Foster a culture that improves employee and public safety;
- Enhance efficiency and increase customer value by deploying new techniques, technologies, industry best practices, and process improvements;
- Ensure compliance with applicable regulations, including those addressing T&D grid reliability and operations;
- Support grid modernization plans that include distributed energy resource (DER) optimization, and functions that automate outage restoration and optimize the performance of the grid; and
- Streamline and develop better ways to plan for and interconnect transportation electrification needs, DERs, building electrification, and use technologies, such as batteries, through the Distribution System Planning process.

Q. How is the remainder of your testimony organized?

A. After this introduction, our testimony is organized as follows:

- Section II: Capital Projects Since UE 335
- Section III: Transmission and Distribution O&M for 2022
- Section IV: Integrated Grid Strategy Overview
- Section V: Wildfire Mitigation
- Section VI: Vegetation Management
- Section VII: Level III Outage Restoration

- Section VIII: Summary and Qualifications

II. Capital Projects Since UE 335

Q. Please summarize the T&D capital additions from January 1, 2019 through April 30, 2022.

A. PGE is continuing our ongoing work to replace aging infrastructure to maintain reliability as our system continues to grow. We are also building additional facilities to strengthen our system and support future technology. PGE's total T&D capital additions for January 1, 2019 through April 30, 2022, are $1,566.3 million net of $119.2 of depreciation, with the IOC representing the single most significant portion of those costs at $215.2 million.[1] Table 1 below breaks down the areas of investment over the period.

Table 1
T&D Capital Additions
($millions)

Category	Additions
Poles & Wires	$ 809.1
Substations	$ 351.7
Integrated Operating Center (IOC)	$ 215.2
Line Transformers	$ 67.8
Meters Additions and Replacements	$ 53.5
Advanced Distribution Management Systems (ADMS)	$ 27.4
Field Voice Communications	$ 17.4
Field Area Network (FAN)	$ 16.2
Remote Sensing Project	$ 8.0
Gross Plant	**$ 1,566.3**
Net Plant*	**$ 1,447.1**

** Net of accumulated depreciation.*

[1] Under the Federal Energy Regulatory Commission accounting definition of functional classes, the IOC, ADMS, Field Voice Communications, FAN, and the Remote Sensing Project are General Plant or Intangible Plant. They are included here as they are operationally T&D projects. Costs are appropriately functionalized during the unbundling of costs.

Q. Why are January 1, 2019 and April 30, 2022 the appropriate beginning and end dates for this discussion?

A. Docket No. UE 335 was PGE's previous general rate case (GRC) wherein rate base was established as of December 31, 2018 and approved by Commission Order No. 18-464. As noted in PGE Exhibit 200, rate base for this GRC is being established as of April 30, 2022, prior to a May 2022 rate effective date.

Q. What kind of work is included in the $809.1 million of poles and wires investments over the period?

A. Poles and wires investments include:

- $317.2 million of poles and wires related to a myriad of projects including transmission line clearance mitigation, wildfire mitigation, and other projects such as the Marquam Substation Project, Blue Lake Phase II Project, Division Transit Project, and Horizon Phase II Project.
- $183.2 million in blanket T&D projects focused on major system inspections and upgrades, and distribution system line construction needed.
- $148.3 million in specific customer related projects for new connections and load growth.
- $92.5 million related to underground work, such as the replacement of failed underground cables and the unjacketed cable replacement program.
- $36.3 million related to the damage caused by the 2020 Labor Day wildfires and the 2021 February winter storm.
- $18.6 million related to Distribution Automation (DA) schemes at various locations – this includes items such as reclosers, and

- $13.0 million related to transformer upgrades and replacements.

Q. What kind of work represent the $351.7 million of substation investments over the period?

A. The substation work is predominately driven by investments in the following areas:

- $130.6 million on new substations built to serve new load growth and improve system flexibility.
- $78.2 million on substation rebuilds, the majority of which is related to the Harborton Reliability Project, which was redesigned and rebuilt to provide increased reliability to customers supported by the T&D systems in the area.
- $51.4 million on conversions and upgrades to substations, often to address heavily loaded systems.
- $32.7 million on substation expansions to address additional capacity needs, and
- $19.9 million on substation related FITNES.[2]

Remaining amounts are for investments in a variety of other categories including but not limited to security upgrades, switch replacements, replacements of failed transformers, arc flash mitigation, etc.

Q. What are the most significant T&D capital projects since UE 335 that will be placed into service by April 30, 2022?

A. Other than the IOC, since UE 335, PGE had 18 significant projects, each greater than $10 million, placed into service or expected to be placed into service by April 30, 2022. In aggregate, these projects account for $451.8 million of the $1,566.3 million of T&D capital additions. Details of these projects are provided in PGE Exhibit 801.

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[2] Facility Inspections and Treatment to the National Electric Safety Code.

Q. What value will these T&D investments provide to customers?

A. These investments provide value to customers by maintaining a strong and reliable grid as we strive to achieve targeted decarbonization goals and create an integrated grid inclusive of DERs, while simultaneously proactively protecting our system and our customers from wildfires and other severe events by making it more resilient.

In addition to the buildout of the IOC and investments made in ADMS to support an integrated grid, we have invested in projects to support additional capacity and flexibility on the system, projects to support the new and growing load of customers in certain areas, and projects that replace aging infrastructure, improve safety, and meet or maintain National Electric Safety Code (NESC) which is inspected by Public Utility Commission of Oregon (Commission or OPUC) Safety Staff, the North American Electric Reliability Corporation (NERC) compliance requirements, and all applicable standards.

Q. Why did PGE choose to make such large capital investments in its T&D system at this time?

A. PGE made these investments in its T&D system over the past three years to improve service to customers, withstand increasing weather events due to climate change, increase visibility and operational capabilities across the grid, deploy DERs, and plan and architect a responsive grid using advanced technologies to prepare ourselves for changes underway in our industry. As we move toward a cleaner energy economy, our customers will be able to interact with the electric grid in new and innovative ways, from the use of electric vehicle charging stations at home with backup batteries, to the use of other DERs and flexible load management programs. The electric grid must be ready to handle these technologies, and changes. Therefore, it has been imperative that our system is prepared by investing in it.

In addition to the investments we have made to prepare for a more integrated grid, many of the investments that PGE made over the last three years have been related to replacing aging infrastructure, improving safety, maintaining compliance with NERC requirements, and supporting load growth in the area. By their nature, these activities are core practices to maintaining reliability and safety, and therefore cannot be delayed. PGE Exhibit 801 helps to highlight the various projects completed for these reasons.

Q. Did PGE consider reducing its capital spending as a result of the COVID-19 pandemic?

A. Yes. However, most of the capital additions included in this rate case had either already been completed or had work underway prior to the pandemic. When the severity of the COVID-19 pandemic became clear in March 2020, PGE reviewed and reduced its total targeted capital budget for 2020 by $150 million with a significant portion allocated to T&D. T&D achieved $65 million of actual reductions in 2020 as a result of these actions. For 2021, PGE reduced its total capital budget by $50 million, a large portion of which was again T&D. It should be noted that customer demand for new construction connects continued with no slow down during the COVID-19 pandemic.

III. Transmission and Distribution O&M for 2022

Q. Please summarize the T&D O&M costs for the 2022 test year.

A. As shown in Table 2 below, T&D O&M costs are forecasted to be $172.6 million in 2022. This represents a $25.9 million increase from 2020 actuals, or an 8.5% annualized increase.

Table 2
T&D O&M ($ millions)

	2020 Actuals	2021 Budget	2022 Forecast	Variance 2020 – 2022	Annualized % Increase
T&D Labor	$63.2	$70.9	$78.7	$15.5	11.6%
T&D Non-Labor*	$68.6	$65.4	$79.0	$10.4	7.3%
Subtotal T&D	**$131.8**	**$136.3**	**$157.7**	**$25.9**	**9.4%**
Information Technology	$14.9	$14.7	$14.9	$0.1	0.2%
Total T&D O&M**	**$146.7**	**$151.0**	**$172.6**	**$25.9**	**8.5%**

**Labor loadings included in non-labor*
***May not sum due to rounding*

Q. What are the primary drivers for the increase in T&D O&M costs from 2020 to 2022?

A. The primary drivers of T&D O&M cost increases are grid modernization, wildfire mitigation, vegetation management, and the Level III outage accrual.

The grid modernization increase includes $3.2 million of incremental O&M expense associated with the IOC and $3.4 million for ADMS. The IOC and ADMS will be discussed in detail in Section IV where we provide an overview of our Integrated Grid Strategy and its value for our customers.

The wildfire mitigation increase includes $4.6 million of incremental O&M expense related to our Wildfire Mitigation Program and associated Wildfire Mitigation Plan, which have been developed over the past two years as wildfire has become an increasing threat to our system and our ability to serve customers. The Wildfire Mitigation Program and Plan are discussed in detail in Section V.

The vegetation management increase includes $22.6 million of incremental O&M expense related to implementing an initiative to evaluate and strategically adjust tree trimming cycles, and the implementation of Advanced Wildfire Risk Reduction (AWRR) and Enhanced Vegetation Management (EVM), which is discussed in Section VI.

The ten-year average for PGE's Level III outage accrual will increase by $6.6 million, driven by increased storm expense since 2019 and is discussed in Section VII where we also discuss our proposal to revise the Level III outage mechanism.

Q. Has PGE achieved any T&D O&M efficiency gains over the past several years to offset these cost increases?

A. Yes. PGE has achieved significant cost savings in T&D O&M over the past several years, which help offset the cost increases listed above. These savings are achieved through a combination of measures that reflect our commitment to continue operational improvements and keep costs low for our customers. Below are a few examples of programs and initiatives that serve as drivers for the T&D costs savings realized:

2020: $1.4 million reduction in line center labor due to operational efficiencies; and $0.8 million reduction from storeroom inventory efficiencies.

2021: $10.7 million reduction in line operations O&M by reprioritizing work, right-sizing crews and transferring work from contract labor to PGE employees; $1.3 million reduction in substation operations costs through a 50% reduction in overtime and reduced materials costs by shifting from scheduled maintenance rotations to condition-based maintenance where possible; $1.1 million reduction in Geospatial Information System (GIS) expenses due to completion of GIS data cleanup efforts; $0.9 million reduction in training and travel by emphasizing in-house training; $0.5 million reduction in contract labor usage and increased usage of PGE labor; and $0.4 million reduction in fleet fuel purchases by renegotiating PGE's fleet fuel contract.

As shown by these efforts, PGE is committed to finding additional savings going forward to operate effectively and efficiently to meet our customers' needs.

IV. Integrated Grid Strategy Overview

Q. Please briefly describe PGE's grid modernization plan.

A. Our grid modernization plan is a phased, multi-year and multi-program approach to better maintain and improve reliability and resiliency of the electric grid as new and innovative technologies are adopted by our customers. Grid modernization is intended to enable our customers to seamlessly interface with the grid through these technologies without disruption to our ability to deliver electricity reliably and safely.

PGE's grid modernization plan includes near-term projects, such as the IOC and ADMS; and the completion of future projects including Field Area Network (FAN), Distributed Resource Planning (DRP), and DA.

Q. Please briefly describe each of the projects and programs identified above as a part of PGE's grid modernization plan.

A. The IOC and ADMS will be explained in detail below. PGE's FAN is a wireless communication network for sending commands and retrieving data from field sensors and control devices throughout an electrical distribution system. DRP is a program that allows PGE to develop a planning process to optimize the efficiency of its distribution system and maximize the customer value as we continue to electrify our energy economy in service of our decarbonization goals and the state's climate goals. Finally, DA is a program that is a family of technologies, including sensors, field devices, processors, and switches, through which a utility can collect, automate, analyze, and optimize data to improve the operational efficiency and reliability of its distribution system. While each of these projects and programs are essential to modernizing the grid, they are not the only actions we will be taking. We will continue to assess what we need to serve customers as we move through our phased approach.

The phased approach will allow us to grow and evolve with our customers' energy needs as we move forward with grid modernization.

A. Integrated Operations Center

Q. What is an Integrated Operations Center?

A. An IOC is a facility that centralizes all mission-critical operations that maintain the flow of power to customers. These operations include primary support functions, including the System Control Center (SCC), Cyber Security, Physical Security, and Network Security. The IOC will be a critical part of PGE's strategy to deliver the reliable, resilient, affordable clean energy future our customers need and expect. It will provide immediate and enduring value to customers through:

- Resource and system integration: Weaving together clean energy resources and smart technologies into a seamless, reliable whole – renewable power, flexible load (demand response), distributed energy resources, storage, regional resources (e.g., Energy Imbalance Market).
- Improved reliability: Daily grid management of load/generation, transmission, and distribution with advanced visibility and control for improved reliability and outage response (for both routine and extreme weather events and catastrophic events, such as wildfires).
- Increased resilience and security: Strong physical and cybersecurity to meet critical infrastructure standards; seismic and other natural disaster-readiness; extended off-grid operational capacity to facilitate recovery operations.

The critical functions that PGE plans to house at the IOC are discussed below.

Q. What is the difference between an IOC and an SCC?

A. An SCC is a facility that houses the portion of the mission-critical operations that control the flow of power on the grid. An IOC includes SCC functions, and in addition, will include Cyber Security, Physical Security, and Network Security. The IOC will include a new Distribution System Operation (DSO) team that will monitor and manage the details within the distribution network.

Q. Why does PGE need an IOC and how does it benefit customers?

A. By integrating the relevant people, functions, and systems into a single facility, PGE will be able to maximize the effectiveness of the grid modernization initiative and provide a more reliable and resilient system for our customers. In addition, an IOC will allow for the direct analytics and security support that is needed to effectively operate the future electrical grid, which cannot be achieved with simply rebuilding or replacing the control center. The IOC is critical to the successful transition to a more complex, smarter, more flexible power grid that can reliably integrate a diverse portfolio of renewable and distributed generating resources and load management systems.

Furthermore, delivery of power to PGE's customers during and after a disaster is critical for the safety of the communities PGE serves. A seismic evaluation performed on the current location of PGE's SCC and other grid-related functions, the 3 World Trade Center (WTC),[3] determined that although the 3WTC building is fit for general purpose activities, it has deficiencies for mission-critical activities that could result in localized hazards or partial or total collapse of the structure in a major seismic event.

Additionally, the nature of the 3WTC facility and its urban location have required additional security resources to address the trend of increasing encounters with protesters and

[3] See PGE Exhibit 802.

individuals engaged in civil unrest. In addition to reliability and resiliency risk concern mitigation, PGE's IOC will better allow us to bring together grid control, and cyber, physical, and network security into one center. The needed space is not available at WTC and simply providing the needed seismic upgrades designs for 3WTC was estimated to cost $350 million. The IOC includes the implementation of an ADMS, expansion of Dispatchable Standby Generation (DSG), Enterprise Data Analytics, and expansion of the Reliability Performance Monitoring Center.

The IOC will provide value to customers through both enhanced day-to-day functioning of a more efficient, cleaner, and more flexible power grid and through improved resilience in the face of routine and extreme natural and human threats to physical and cybersecurity and network operations.

Q. When do you expect the IOC to be operational and in-service?

A. The IOC is on track to be commissioned, operational, and placed into service in the fourth quarter of 2021. Occupancy will be phased in over several months.

Q. Could PGE's back-up control center, located in Oregon City, be redeployed as the primary control center (and 3WTC made into the back-up control center)?

A. No. The back-up control center, located in Oregon City, was designed for emergency use only and constructed in compliance with the NERC EOP-008-2[4] standard. It was sized appropriately to house only mission-critical functions. While it is adequate for its purpose, the site does not allow for expansion to accommodate an IOC. Additionally, the 3WTC would not be a viable back-up control center due to geographic and security risks.

[4] See NERC EOP-008-02

Q. Please describe how the IOC will improve PGE's resilience in the event of a Cascadia Subduction Zone event or similar event that could cause widespread outages.

A. The IOC is being constructed with a technology called 'base isolation' that utilizes base isolators beneath the building that will absorb the seismic energy produced by a Cascadia Subduction Zone event. During the event, the building will sway rather than shake and, consequently, maintain its structural integrity. The facility will have redundant utility services (water, electricity, etc.) to operate in isolation for two weeks, will host the emergency operations center, has space and connection available for Federal Emergency Management Agency or state trailers, and will have space for field personnel to organize, as necessary. This will minimize the risk that PGE will need to spend time recovering its own operations and, as a result, provide more time to focus on addressing customers' needs.

Q. Are there other benefits to customers of the IOC?

A. Yes. Performance metrics will improve through the implementation of all the component projects of the grid modernization initiative (and are more specifically defined with those projects). As planned, the IOC is expected to:

- Provide the foundational infrastructure needed to implement and operationalize the grid modernization initiative;
- Mitigate the risk of future disasters impacting the operations of the electric grid;
- Improve resiliency of PGE's IT infrastructure by incorporating the Data Center, Integrated Security Operations Center (ISOC), and Integrated Network Operations Center into the IOC, and Physical Security Operations;
- Improve corporate resiliency by implementing a corporate Emergency Operations Center;

- Enhance work design to address significant employee retirement impacts and technological advancements in a changing industry; and
- Enable, due to co-location of mission-critical and support operations, holistic and economically optimized decisions, increase situational awareness and collaboration between departments, expand cross-training opportunities, and facilitate a comprehensive training program to support reliable operation of the grid and maintenance of NERC certification for compliance.

Q. What process did PGE use to plan, design, and build the IOC?

A. PGE retained specialists who have worked with other utilities that have developed IOCs to guide PGE's requirements development process and assist with evaluating alternatives. PGE personnel also toured several emergency centers across the nation while looking for best practices. PGE also used the customary Construction Manager/General Contractor (CM/GC) delivery method with a guaranteed maximum contract price, and selected vendors for the roles of Owner's Representative, Architect/Engineer, and CM/GC. See PGE Exhibit 803 for descriptions of these roles.

Q. Please identify which functions will be housed in the IOC.

A. Current SCC personnel, Power Operations, Cyber Security, Physical Security, Network Security, DSG, BCEM, Wildfire, Transmission and Market Operations, and Integrated Operations functions will be housed in the IOC. Field crews will not be housed in the IOC. Specific functions to be housed at the IOC are identified in Table 3 below.

Table 3:
Functions Housed at the IOC

Transmission/Distribution Operations
Balancing Authority
Transmission & Distribution Dispatch
Transmission Scheduling
Transmission Operations Engineering
Generation, Transmission, and Distribution Outage Coordination
Operational Technology Operations & Planning Engineering
Grid Technologies
Distribution Operations Engineering
Dispatchable Standby Generation (DSG) and Demand Response (DR) dispatch
Power Operations
Merchant Real Time Operations (MRTO)
Day Ahead Trading & Fuel Management
Merchant Transmission & Resource Integration
Market Fundamentals Analysis
Integrated Operations
Physical Security
Integrated Security Operations Center (ISOC)
Integrated Network Operations Center (INOC)
Business Continuity and Emergency Management (BCEM)
Wildfire Mitigation (WM)
Emergency Operations Center
Reliability Performance Monitoring Center
Data Center Operations
Energy Infrastructure Technology (EIT)
IT – Operations Applications
Market Performance
Risk Management

Q. Will moving these functions to an IOC result in a change to PGE's long-term operating expense trends (e.g., net increase or decrease of employees)?

A. Yes. The facility will initially be staffed at 220 employees, most of whom will move from the downtown WTC buildings. Moving these employees will reduce WTC rent space percentage from 67.1% to 48.8%. As a result, PGE's overall rent expense is expected to decrease from \$8.5 million in 2020 to \$6.2 million in 2022, a reduction of approximately \$2.4 million. The IOC-related O&M labor increases are the result of the cost of additional contract security guards, DSOs, Outage Communications Specialist (OCS) positions, and a facilities maintenance person. O&M expenses will also cover the typical O&M costs associated with a building of this type, such as landscaping services, battery maintenance, generator maintenance, janitorial services, sewer, water, communications leases, etc. The total annual O&M for the facility is estimated to be $3.2 million.

Q. Please describe the criteria PGE used to determine which functions should be housed in the IOC.

A. PGE project administration identified functions most closely aligned with PGE's mission and associated strategy to provide safe, reliable, and clean energy solutions to power its customers' lives every day. PGE Exhibit 804 contains both IOC critical functions and support function criteria established by PGE project administration. Any function that met the mission-critical[5] operations or resiliency was identified as a candidate for relocation to the IOC. Any function that met the support and/or tools/systems function was also identified as a candidate for relocation to the IOC. The candidate recommendations were then presented to the PGE Operations Steering Committee officers and received approval in 2018.

Q. Please describe the phase-in or staggered approach to moving employees/functions to the IOC.

A. As mentioned above, the functions that will be operating in the IOC represent the critical operations of PGE. To minimize risk of disruption to the electrical grid and service to customers, PGE is planning to complete a detailed commissioning and testing plan of the facility prior to moving functions into the IOC. The commissioning plan will thoroughly test

[5] The mission-critical operations group works 24/7 to support energy is reliably and economically purchased from the market, scheduled and generated from power plants, delivered to load centers, and dispatched across PGE's T&D system.

the building to validate that all systems remain operational during a major event. The commissioning plan will include testing of the communications infrastructure, hardware, and software used to operate PGE's generation, transmission, and distribution systems. PGE will then operate from the IOC in parallel with the current WTC location until operational systems are proven reliable. Once PGE is satisfied that systems are functioning reliably and operational performance criteria is obtained, employees/functions will transition to the IOC in a staggered approach and cease to operate at their current location. As some functions are more critical than others, PGE will schedule timelines associated with these steps according to their criticality and complexity as more critical and complex functions will require more time. This results in the staggered nature of moving employees/functions. In addition, the moving of the SCC requires NERC and Western Electricity Coordinating Council certification.

Q. Have other utilities and entities in the US created or planned to create an IOC?

A. Yes. Florida Power & Light (FP&L), Los Angeles Department of Water & Power (LADWP), California Independent System Operator (CAISO), and Arizona Public Services (APS) have constructed or renovated sites for IOCs. Both the Bonneville Power Administration (BPA) and the Tennessee Valley Authority are in the process of planning their own IOCs. BPA has been meeting with PGE personnel and has chosen to utilize the same architectural contractor that PGE used to design its IOC.

Q. What lessons did PGE learn from working with utilities that have already created their own IOCs, and how did those lessons improve your plans and processes?

A. PGE's IOC project stakeholders visited newly constructed and renovated sites at peers that included FP&L, LADWP, CAISO, and APS. Lessons learned from these visits include:

- Plan for potential future expansion: Peers' centers, in some cases, became crowded within years of construction or renovation either because of staff and/or infrastructure growth to respond to industry and market changes. PGE worked with its Architect/Engineer to design a facility that could accommodate growth through flexibility in the usage of its spaces.
- Design open workspaces to encourage collaborative and productive exchanges between functions: PGE worked to affirm this open-plan style and incorporate it into the space planning process with the project architect.
- Ensure that compliance with regulatory requirements is addressed throughout the process: Peers have found that their facilities can become very difficult to retrofit to comply with certain new standards (especially regarding critical infrastructure security). The PGE IOC project team includes stakeholders that represent regulatory compliance in the design process with the additional directive to plan for future regulatory requirements (such as the potential for the distribution system to be regulated similarly to the transmission system). Additionally, PGE retained Burns & McDonnell, a well-known and respected construction engineering company, to assess the IOC design for physical security concerns.

Q. Please describe the IOC site selection process.

A. The Site Selection Committee (Selection Committee) was created by the internal project sponsors in December 2017 and was composed of representatives from the following departments within PGE: System Control Center; Power Operations; Real Estate & Facilities; Business Continuity & Emergency Management; Security; and IT Business Relationships.

In January 2018, the Selection Committee began the site selection process by identifying the most important characteristics that would need to be considered in the site selection and developing a process for assessing candidate sites. The criteria and scoring used by the Selection Committee are listed in PGE Exhibit 805.

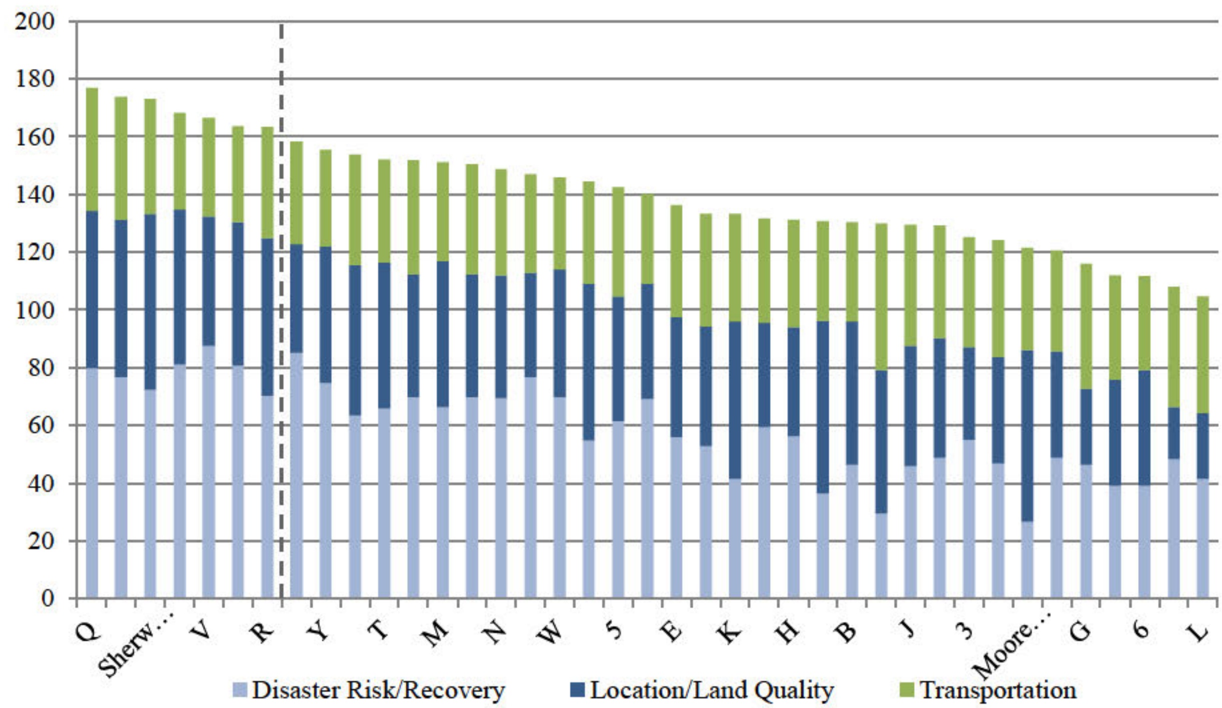
Q. Please describe how the criteria were used in scoring each site.

A. The criteria were divided into three categories: (1) Location/Land Quality; (2) Transportation; and (3) Disaster Risk/Recovery.

The Selection Committee provided these criteria to PGE's preferred real estate broker for identification of available sites and scoring. The real estate broker then provided a list of 38 potential sites for consideration (including two PGE-owned sites) along with their associated scores (see "Figure 1: Prospective Site Scores" below). Scoring was also provided for the WTC complex for comparison. The broker was able to score most items in the criteria developed by the Selection Committee. The broker did not score items in the criteria that required detailed investigation or engineering studies to be performed, such as, buildable acreage, appropriate zoning, site serviceability, future expansion, impact adjacent uses, site preparation costs, and proximity to airport flight path. Regarding zoning, the broker was confident all the sites would either meet the current zoning status or could be changed to meet it.

To avoid bias in the process, the Selection Committee elected to reduce the number of potential sites to the top seven scored sites without knowing the location of the sites. The dashed vertical line in Figure 1 below, separates the top seven scored sites from the remainder of the sites.

Figure 1:
Prospective Site Scores



The seven scored sites were reduced to three after a thorough evaluation of environmental conditions, serviceability to the facility, and proximity to a major natural gas pipeline (details of the environmental evaluations along with site scores are in PGE Exhibit 806). Specifically, the evaluation of environmental conditions resulted in the removal of two sites from consideration, and the evaluation of serviceability resulted in the removal of two additional sites from consideration. An additional site was removed due to multi-parcel/multi-ownership complexity, and another due to a large gas pipeline traversing the property, resulting in three final sites remaining for consideration.

The final three sites ('P', 'Q', and 'V') were provided to the design team for further assessment. The Selection Committee also requested that the project Architect/Engineer consider the PGE-Sherwood site for further assessment to maximize the chance of leveraging property already owned by PGE for the IOC. The project Architect/Engineer evaluated advantages and constraints for each of the four sites based on research and meetings with each of the jurisdictional authorities. The project Architect/Engineer also completed the scoring of the criteria identified by the Selection Committee and provided an overall scoring comparison, shown in Table 4, below. PGE Exhibit 807 – IOC summarizes the activities that were undertaken to arrive at the site recommendation.

Table 4
Architect/Engineer Scoring of Final Four Sites

Criteria	Weight	PGE Sherwood	Site P	Site Q	Site V
Site Acquisition Risk * Most Risk ***** Least Risk		*****	****	***	***
Site and Environment * Most constrained *****Least constrained		*	***	****	**
Land Use Timelines * Complex/Uncertain Process ***** Simple/Fastest Process		***	****	****	**
Location & Land Quality	40%	72.0	86.0	94.8	64.4
Transportation	20%	40.0	42.6	42.6	34.2
Disaster Risk and Recovery	40%	84.4	85.2	88.4	101.6
Totals	**100%**	**196.4**	**213.8**	**225.8**	**200.2**

Q. Why did PGE select the Tualatin site for its IOC?

A. The Tualatin site earned the highest score from the process developed and managed by the PGE IOC project Selection Committee. PGE officers and the finance committee of the Board of Directors reviewed the process and validated the decision in the 4th quarter of 2018. The request to approve purchasing the Tualatin site (Site Q) for the IOC site was presented to and subsequently approved by the finance committee of the PGE Board of Directors at its October 23, 2018 meeting.

Q. Please discuss the total expected capital cost of the IOC.

A. The total expected capital cost of the IOC is $215.8 million, with $215.2 million closing to plant by April 30, 2022. Table 5 below lists the costs by category.

Table 5
IOC Cost by Category

Category	Expected Cost
Site Acquisition and Development	$11,314,183
Professional Services	$10,928,488
Direct Construction	$123,001,025
Owner's Engineer	$4,658,737
Furniture, Fixtures & Equipment	$4,820,760
Operations Technology	$24,416,958
Owner's Costs	$9,171,008
Contingency Reserve Owner	$11,648,201
Allowance for Funds Used During Construction	$15,800,000
Project Total	**$215,757,360**

Q. Please describe the costs for each of these cost categories.

A. Below are descriptions of the types of costs included in each cost category listed in Table 5.

Site Acquisition and Development is comprised of expenses related to the purchase of the property on which the IOC will be located, property taxes, and various site improvements.

Professional Services includes the services of the architect and engineers, independent cost estimation services, security threat assessment, environmental assessment, soils investigation and testing, traffic study, microwave design services, and geotechnical study.

Direct Construction is the construction and insurance costs associated with demolition, site preparation and construction of the IOC.

Owner's Engineer is the cost of the independent oversight services that PGE retained during the project. These include the Owner's Engineer that is overseeing the process from end-to-end and conducting the commissioning (testing) of the facility attributes as they are completed. This also includes an engineering peer review of the base isolation design (both from a structural and geotechnical aspect) that the IOC will rely on to withstand seismic events.

Furniture, Fixtures & Equipment includes the costs of all the furniture and equipment required for the general outfitting of the facility for service.

Operations Technology refers to the specialized equipment and technology systems that are specific to an IOC. These include the installation of a communication system, audio-visual infrastructure to support the situational awareness requirements of the T&D grid operators, and redundant distribution feeds to the building for enhanced reliability.

Owner's Costs are the costs incurred by PGE in the completion of the project. These include land permitting, local plan reviews, development fees, legal services, project management, external oversight (in coordination with PGE internal audit), project employee labor, environmental mitigation, and moving costs.

Contingency Reserve Owner is the amount of contingency PGE was advised to budget by its owner's engineer and validated by its external oversight agent. Some of the risks that were cited included uncertainty regarding application of the Oregon business receipts tax, effects of trade disputes on component prices, potential design changes, and unknown site issues.

Allowance for Funds Used During Construction (AFUDC) covers the financing costs required to fund the project (see PGE Exhibit 200, Section VI, for a summary of AFUDC).

Q. What processes did PGE use to develop the cost estimate for the IOC?

A. The project Architect/Engineer worked with PGE project stakeholders to develop a space program and master plan to initiate the facility design process. The PGE project team directed the Architect/Engineer to adjust the design during the schematic design process to reduce costs and reflect a more economical facility while still meeting the scope.

The PGE project team, including the CM/GC, Owner's Representative, and Architect/Engineer, completed a value engineering effort to reduce the construction cost of the facility while maintaining the scope. The revised design was re-estimated by the CM/GC. In addition, PGE project stakeholders were tasked with developing budgets related to their functions, which were presented to the project team and executives, and assessed for opportunities for reduction before they were finalized.

Q. What cost control measures did PGE employ during the planning, design, and construction of the IOC?

A. PGE retained the services of an Owner's Engineer to identify opportunities for savings in the design of the IOC and the direct construction budget. Rather than utilize the more common design-bid-build delivery method, it was determined that the project should use a CM/GC delivery method to reduce the amount of time required between the design and construction phases of the project.

The CM/GC prepared a cost estimate of the IOC (construction costs only) based on the schematic design and reconciled it with that of a third-party estimating firm retained by PGE.

The Architect/Engineer, working with the rest of the PGE project team, developed the detailed design and initial construction drawings for the CM/GC to develop a Guaranteed Maximum Price (GMP) for construction of the IOC. The GMP was validated by the third-party estimating firm prior to negotiating a revised GMP, which was lower than originally proposed by the CM/GC. PGE executed a contract with the CM/GC for construction based on the revised GMP.

Both Washington County and the City of Tualatin provided concessions in the development requirements/land planning process that reduced costs. Washington County relieved PGE of the requirement to expand a local roadway that would have normally been required with this type of development. Instead, Washington County will include that roadway expansion as part of a future project that it will build. The City of Tualatin allowed PGE to defer indefinitely the building of a local roadway that was required as part of a master plan adopted for the area. Additionally, the City of Tualatin provided cost-effective alternatives to the project designs for utility access. These included reduced requirements and access to more favorably proximate public utilities that proportionally decreased the amount of construction materials for which PGE needed to budget.

Q. Did PGE consider a long-term lease rather than owning the IOC?

A. Yes. The unique nature of the operation of the IOC facility would have required much more control on the part of the tenant than landlords are typically willing to concede. Given the substantial capital improvements associated with the IOC facility, a lease would need to be very long-term (e.g., 40 years or more) which, in addition to the characteristics required for the IOC, significantly limits available counterparties. Typically, monthly lease payments would, over time, exceed the cost of funds or debt service associated with the property. Given the length of the lease term, landlords would almost certainly include a provision increasing the lease payments annually. In addition to the base rent, the typical triple-net lease agreement makes tenants responsible for "ownership" type expenses such as insurance, property taxes, utilities and maintenance costs.

Q. Did PGE consider making upgrades to its current location at 3WTC rather than building the IOC?

A. Yes. After receiving the seismic report on 3WTC, and prior to deciding to build the IOC, PGE obtained a cost estimate from DCW Cost Management to retrofit 3WTC to a Risk Category IV, the level needed for the location to be suitable for mission critical operations, and the cost was estimated to be $350 million, making the construction of the new IOC a less expensive option for customers.

Q. Please summarize your IOC testimony.

A. To provide the most reliable and resilient grid for our customers, PGE must integrate the relevant people, functions, and systems into a facility that will be operational during a variety of natural disasters. An SCC must be able to withstand various types of natural disasters, including a major seismic event, so that PGE can continue to operate the electrical grid during and after such events. PGE's current SCC does not meet these needs, and the cost to retrofit it is not cost-effective.

The IOC is also the key element of PGE's grid modernization initiative and will play a critical role in supporting the transition to a clean energy system by integrating renewable and distributed resources and flexible load management programs, centralizing all the mission critical smart grid operations that maintain the flow of power to customers and their primary support functions. The IOC is constructed using a base isolation design (both from a structural and geotechnical aspect) to withstand seismic events, and will have redundant utility services (i.e., water, electricity, communications, etc.) that enable it to operate in isolation after a disaster. In addition, it is located and designed to comply with the NERC Physical Security Perimeter requirements for SCCs.

The total expected capital cost of the IOC is $215.8 million, with $215.2 million closing to plant by April 30, 2022. PGE conducted a rigorous selection process to identify the functions that need to be housed at the IOC, and an equally rigorous process to identify options, potential sites and to make the final site selection. PGE also engaged experts to assist in identifying options, site selection, design, and construction, while also employing stringent cost control measures.

B. Advanced Distribution Management System

Q. Please briefly explain ADMS.

A. ADMS is an operational technology system (software platform) that supports the full suite of distribution management, DA, DER optimization, including predicting, monitoring, controlling, optimizing, and safely operating all elements within a distribution system. ADMS functions being developed by utilities include fault location, isolation and restoration; volt/volt-ampere reactive optimization; conservation voltage reduction; flexible load integration; and support for microgrids and transportation electrification.

Q. Please briefly describe PGE's ADMS program.

A. PGE is pursuing a multi-phase ADMS program, with the first phase presently underway and scheduled for completion by the end of 2021. This first phase includes:

- Distribution Supervisory Control and Data Acquisition (SCADA) including separation of distribution SCADA devices from the existing Energy Management System (EMS) SCADA system;
- Network Modeling and Topology Processing;
- Power Flow / State Estimation, Switch Order Management;
- Fault Location, Isolation and Service Restoration (FLISR) for three feeders only, but to be expanded in future phases; and
- Visibility for selected DER and DR events.

We expect future ADMS program phases to include Volt Var Optimization/CVR, enhanced Distributed Energy Resource Management System (DERMS) functionality, and integrated Outage Management System capabilities as determined appropriate. The scope for the next phase (and future phases) of the ADMS program will be defined as the program progresses and PGE gains experience implementing and operating ADMS.

Q. What ADMS costs are reflected in this case?

A. As explained below, this case includes capital costs of $30.6 million, $27.4 million of which exists in T&D and $3.2 million in general plant, and O&M of $3.8 million related to Phase 1 of the ADMS program.

Q. Please describe the benefits to customers of implementing ADMS.

A. Phase 1 of ADMS will provide several key benefits to customers:

- A platform on which various applications can be implemented such as FLISR, dynamic feeder reconfiguration, and fault protection analysis, all of which will result in a reduction of customer outage duration;
- A real-time view of the state of the distribution system (via power flow and state estimation), enabling proactive identification and resolution of distribution system overloads/under-voltages/over-voltages;
- Support for the separation of Transmission System Operator (EMS) and Distribution System Operator (ADMS) roles to enable dedicated operators to focus on the distribution system, which will provide opportunities for them to respond faster to customer outages;
- Support for migration to electronic switching orders (rather than paper maps presently used for distribution switching); and
- A "single source of truth" for the as-switched state of the distribution network.

These changes will allow PGE to move toward the integrated grid of the future and improve visibility into the system.

Q. Please describe how PGE's ADMS program aligns with its other grid modernization programs.

A. ADMS will enable provision of centralized command of field and substation devices (e.g., breakers, load tap changers, capacitor banks). These centralized commands will utilize FAN to communicate with those field devices and specialized equipment such as reclosers and remote fault indicators that are deployed under the DA program. ADMS hardware and software will be housed in the IOC facility. Further, advanced applications such as DERMS, mobile grid operations, and OMS will integrate with ADMS to provide essential information to operators and engineers. PGE Exhibit 808 shows the core functionalities of ADMS, a conceptual view of PGE's grid management system, and the relationships between EMS, ADMS, FAN, DA, DERMS, etc.

Q. Why does PGE need an ADMS?

A. PGE has a vast distribution grid consisting of ~700 feeders and ~220 substations. Currently, PGE does not have a distribution management system. PGE monitors the distribution system using the EMS system for substations and OMS system for customer meters. The primary function and purpose of the OMS is to react to and manage outages on the system as they occur. With ADMS in place, PGE will have the capability to monitor the distribution grid in real time and predict future power flow conditions and system constraints.

Q. Have other utilities in the United States implemented or begun to implement ADMS?

A. Yes. ADMS has become increasingly important to provide real-time operator awareness of the state of the distribution system and is a platform on which DERs can be optimized. Utilities such as Duke Energy, Consumers Energy, Hawaiian Electric, and other major investor-owned utilities in the West, including Idaho Power, Puget Sound Energy, Oklahoma Gas and Energy, Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San

Diego Gas & Electric (SDG&E), as well as major public power utilities (e.g., Sacramento Municipal Utility District), have or are in the process of implementing an ADMS.

Q. How do the functions that PGE has included in its current ADMS request compare to functions implemented at other utilities?

A. PGE is using a measured and thoughtful approach to ADMS and will implement ADMS in stages. Most utilities implement ADMS in a phased approach, and the request included in this GRC is for only the first phase of PGE's ADMS implementation plan.

Q. What lessons has PGE learned from working with utilities whose ADMS efforts may be more advanced?

A. Some key lessons that PGE has learned from other implementations are:

- Implement ADMS in a phased manner and introduce changes over time;
- GIS data is essential to support ADMS operation;
- Leverage Advanced Metering Infrastructure (AMI) data to support meter to transformer connections and development of load profiles;
- Coordinate areas of responsibility and roles to appropriately segment transmission operations from distribution operations;
- Hire qualified DSOs and train them well in advance;
- Convert manual/paper-based tracking of switch operations to tracking via electronic media; and
- Digitize paper-based mapping process (e.g., substation modeling).

Q. Has PGE engaged independent experts to assist in developing its ADMS program?

A. Yes. PGE engaged services of multiple third parties with different areas of expertise. PGE selected Utilicast to lead ADMS system integration efforts, EnerNex to act as owner's engineer (an independent advocate for PGE) for the project, PricewaterhouseCoopers to develop certain training materials and administer training programs, and 71 & Change to support change management. Each of these organizations has personnel with demonstrated experience in their respective areas.

Q. Are you proposing an increase in ADMS costs compared to historical ADMS costs?

A. Yes. As previously discussed, ADMS is a new program and PGE is still in the process of developing its Grid Modernization program. Prior to 2019, PGE did not have any ADMS-related costs. As a result, all our ADMS costs are incremental to our last GRC. In 2020, PGE spent $0.4 million of O&M and we have budgeted to spend $2.6 million of O&M in 2021 on ADMS development. The 2022 forecasted O&M expense for ADMS is $3.8 million (see Table 6, below).

As for capital, in 2019, PGE spent $6.4 million on capital for ADMS Phase 1, which increased to $13.4 million in 2020 and to $10.8 million in 2021.

Q. Please provide more detail on PGE's 2021 and 2022 amounts for ADMS.

A. Table 6 below summarizes the ADMS program O&M for 2020 actuals, 2021 budget and 2022 forecast. PGE is adding 28 new employees (14 Distribution System Operators, two Grid Tech Engineers, two Grid Tech Analysts, four Distribution Operation Engineers, two Trainers, one Simulator Specialist, one IT administrator, one GIS specialist, and one Distribution Operations Manager), in order to staff ADMS. In 2020, PGE hired 20 of the 28 employees to support ADMS. We plan on filling the remaining eight positions in 2021.

Table 6
ADMS O&M (millions)

	2020 Actuals	2021 Budget	2022 Forecast
Labor	$0.3	$1.3	$3.2
Non-Labor	$0.1	$1.3	$0.5
Total O&M	**$0.4**	**$2.6**	**$3.8**

In addition to O&M, ADMS capital spend is as follows: $6.4 million in 2019, $13.4 million in 2020, and $10.8 million in 2021. The total capital spend of $30.6 million that PGE has employed for ADMS will be placed into service in 2021.

Q. What processes did PGE use to develop the cost estimate for 2021, 2022 and ongoing ADMS efforts?

A. PGE performed three different cost estimates: 1) an internal cost estimate using historical estimates for similar projects; 2) benchmarking efforts with peer utilities (i.e., APS, Oklahoma Gas & Electric, Sacramento Municipal Utilities District, Puget Sound Energy); and 3) consultant estimates from Utilicast and EnerNex.

For ongoing maintenance efforts, PGE benchmarked against Idaho Power, Puget Sound Energy, Sacramento Municipal Utilities District, and Oklahoma Gas and Energy. The ongoing support costs are based on the benchmarking data and internal expertise on managing an EMS, which is a similar effort to managing an ADMS.

Q. What cost control measures has, or will, PGE employ during implementation of its ADMS program?

A. PGE is utilizing fixed price contracts with many of the vendors supporting the implementation to minimize cost variations. Additionally, PGE included liquidated damages clauses in the ADMS vendor contracts to encourage delivery of systems in a timely manner.

Q. How do the costs of implementing ADMS at other utilities compare to PGE's request to implement ADMS?

A. Direct comparisons are difficult as each utility's ADMS implementation is unique. For example, while all ADMS implementations include a Distribution Management System, it is not clear that each implementation includes OMS or DERMS.

Bearing that in mind, EnerNex collected ADMS budget data for several U.S. utilities from publicly available information and determined that ADMS costs increase with the number of customers served by each utility. The resulting chart in PGE Exhibit 809 shows that the costs of implementing ADMS across a variety of utilities range from several million dollars for Austin Energy to approximately $160 million for PG&E.

Because PGE is implementing ADMS in stages, the cost estimate to implement Phase 1 of ADMS is significantly below the cost of implementing the full suite of ADMS programs and tools. While estimates of the full cost of implementing ADMS are still being developed, we expect that the overall cost of ADMS will be commensurate with similarly situated and sized utilities.

Q. Please describe the actions that PGE has taken to implement ADMS.

A. PGE has established a program structure to manage and implement ADMS. We have procured the licenses for commercial off-the-shelf software from Open Systems International, procured and installed infrastructure hardware, assigned internal subject matter experts, and contracted consultants who have experience implementing such a large system. PGE has completed the initial verification and validation of the software and is currently performing user acceptance tests. PGE has also hired new resources (operators, engineers, analysts) that are required to maintain ADMS.

Q. Please summarize your ADMS testimony.

A. PGE's ADMS program is a new program that is part of its grid modernization plan, which includes near-term projects, such as the IOC and ADMS, and the completion of future projects including FAN, DRP, and DA.

ADMS is an operational technology (software platform) system that supports the full suite of distribution management and DER optimization, including prediction, monitoring, control, optimization, and safe operation of all elements within a distribution system.

PGE's ADMS program is a multi-phase project, and the first phase will be completed by the end of 2021. Only costs related to the first phase of ADMS are included in this GRC. In 2019, PGE spent $6.4 million on capital, which increased to $13.4 million in 2020 and $10.8 million in 2021, for a total of $30.6 million. The forecasted 2022 O&M expense for ADMS is $3.8 million.

V. Wildfire Mitigation

Q. Please briefly explain Wildfire Mitigation (WM).

A. PGE began its WM Program in 2018 but has significantly ramped up efforts following the 2020 Labor Day Wildfires. WM is the activity of identifying locations of increased wildfire risk in the system and actions necessary to mitigate the risk of facilities creating or contributing to a wildfire event. WM also includes investigating how to increase the survivability of wildfires and reduce damage to assets.

Q. How have WM efforts in the Western United States evolved over the last several years?

A. In many regions of the United States, particularly the Western states and in particular California, wildfires have become more severe, larger, longer-lasting, more frequent, and more destructive in terms of lives lost and damage to homes, businesses, and other property. This trend has driven an increase in wildfire preparedness by electric utilities and state and federal agencies. In response to increased wildfire risks affecting all Oregonians, Governor Brown signed Executive Order 19-01 creating the Governor's Council on Wildfire Response (Council) in January 2019. Additional actions and state legislation have resulted from the 2020 Labor Day Wildfires.

Q. Please describe Governor Brown's Council on Oregon's Wildfire Response.

A. The Council was tasked with reviewing Oregon's current model for wildfire prevention, preparedness, and response, and with analyzing the sustainability of the current model to provide recommendations to strengthen, improve, or replace existing systems. The Council was able to conduct its review and issue a report and recommendation in November 2019.[6]

Q. What was included in the Council's report?

[6] See: https://www.oregon.gov/gov/policy/Documents/FullWFCReport_2019.pdf.

A. Consistent with best practices, the Council adopted the framework proposed by the National Cohesive Wildland Fire Management Strategy, which establishes three goals:

1. Create fire-adapted communities;
2. Restore and maintain resilient landscapes; and
3. Respond safely and effectively to wildfire.

The Council concluded that Oregon must make significant changes in all three areas. Specifically for utilities, the report included as its first recommendation that Oregon enact legislation requiring utilities to prepare risk-based wildfire standards and procedures inclusive of criteria for initiating power outages, that the Commission use workshops to develop these risk-based standards and procedures, and that all utilities and T&D system owners participate in these workshops.

Q. Did the Governor issue an additional Executive Order directing the Commission to evaluate electric utilities' plans to mitigate wildfire risk?

A. Yes. In March 2020, the Governor issued Executive Order 20-04 directing the Commission to "evaluate electric companies' risk-based wildfire protection plans and planned activities to protect public safety, reduce risk to utility customers, and promote energy system resilience in the face of increased wildfire frequency and severity…". Executive Order 20-04 specifically relied upon the recommendations of the Council related to mitigating utility wildfire risk.

Q. Does PGE participate in Commission workshops as recommended by the Council?

A. Yes, PGE is actively engaged in the OPUC workshops and has shared its learnings from the 2020 Public Safety Power Shutoff (PSPS) event in the Mt. Hood area and the associated

Community Resource Center, as well as how PGE uses weather reporting tools to maintain situational awareness during fire season.

Q. What is a PSPS event?

A. A PSPS event is when electric service to customers in a particular geographic area, a PSPS zone, is turned off when certain hazardous environmental or system conditions exist such as the potential for wildfires. The first step is to pre-identify a high-risk area (i.e., PSPS zone) via a comprehensive risk assessment. Once identified, common factors to consider before initiating a PSPS event include humidity, weather forecast, fire fuel condition, existing fires and threat to electric infrastructure, agency situational updates, on-the-ground observations, and public safety risk.

Q. Does PGE have a WM Plan?

A. Yes. PGE's WM Plan was created by dedicated resources within its WM Program. This program was established to link efforts across the business to form the foundation for a cohesive long-term strategy to reduce wildfire risks through the execution of the WM Plan. The WM Plan provides the overarching strategy for managing fire hazards and reducing fire hazard risk via increased inspections, vegetation management, operational changes in fire season, and wildfire training of our personnel. The WM Plan also provides guidance for building fire mitigation capabilities by developing and implementing design standard changes for PGE assets, and guidance for implementing capabilities necessary to execute a PSPS when necessary. PGE's WM Plan components include:

- Fire risk assessments and modeling;
- Advanced vegetation management practices;
- Additional facility inspections and maintenance corrections;

- Specific design, technology, and construction standards in high-risk fire areas;
- Changes to operational practices;
- Additional situational and conditional awareness tools and monitoring equipment;
- Increased preparedness, response, and recovery plans;
- Increasing the possibility of using PSPS as a measure to reduce risk;
- Thorough communication and outreach plans; and
- Partnerships.

Q. How does the WM Plan serve to support the prevention and management of wildfires?

A. To support a comprehensive approach to the prevention and management of wildfires, the WM Plan is divided into eight tracks, each with its own unique responsibilities as well as collaborative activities to address Preparedness/Mitigation, Fire Season, Response, and Recovery. The tracks include:

1. Persons Responsible for Preparation and Execution of the WM Plan – identifies key persons and program areas.
2. Purpose and Scope – highlights key principles guiding the implementation of PGE's WM Program.
3. Wildfire Risk Mitigation Objectives – highlights key objectives of the WM Plan.
4. Strategic Alignment / Risk Management Approach – provides detail on multi-phased approach.
5. Operating Environment – discusses high fire threat risk zones (i.e., PSPS zones).
6. Wildfire Risk Mitigation Programs & Activities – includes risk management, vegetation management (VM), asset management and inspections and capital

investment, operating protocols, stakeholder engagement, and research and development.

7. Quality Control & Continuous Improvement – includes roles and responsibilities, monitoring and audit, employee and contractor training, and lessons learned process.
8. Wildfire Risk Mitigation Performance Measures – includes program targets and metrics, and outcome metrics.

Together, these eight tracks address key aspects of wildfire risk assessment and mitigation through necessary response and recovery actions should a wildfire event occur, and the success of the plan relies upon continued participation and buy-in from all PGE personnel. See PGE Exhibit 810 for further detail on each of the eight tracks.

Q. Please describe the benefits of implementing PGE's WM Plan.

A. Wildfire risk is an issue facing all Oregonians and requires widespread participation. As a utility we are one part of the solution. By implementing PGE's WM Plan, we minimize the potential for components of the electrical system or equipment to become the ignition source for a wildfire. PGE's WM Plan provides guidance for how PGE will reduce those ignition risks to protect the communities we serve and maintain service to our customers. Key principles of the plan include:

- Ensuring public and employee safety;
- Acting with urgency to mitigate risk of wildfire ignitions, to respond to wildfire events, and to recover from incidents;
- Collaborating with energy partners; agencies; counties; federal, state, and local governments; other industries; communities; and customers; and

- Utilizing a systematic, risk-based approach to identify and prioritize system hardening and resiliency efforts/actions to reduce risk.

Q. Does PGE have a PSPS Plan? If so, please describe PGE's PSPS Plan.

A. Yes. PGE's PSPS Plan is a part of its overarching WM Plan and it outlines the actions PGE will take to prepare for, execute, respond to, and recover from a PSPS event.

As mentioned above, one of the components of the WM Plan is fire risk assessment and modeling, which is foundational to the WM Program. It is through this work that we evaluate our service territory to identify high fire risk areas and designate them as a PSPS zones. In 2020, we identified one location based on that risk assessment work (i.e., the Mount Hood corridor). Since then, PGE has continued to refine the risk assessment modeling and earlier this year identified another six areas that are considered high fire risk areas. There are now a total of seven PGE-identified areas that are considered PSPS zones that will require additional action per our WM Plan.

Additionally, the PSPS Plan may be used in part for other situations when a pre-emptive power shut-off may be necessary to protect the community and parts of the grid, such as during a cyber-attack targeting the bulk power system, volcanic events, or earthquakes beyond the current wildfire PSPS zones.

Q. How has PGE's WM Plan changed as a result of the 2020 Labor Day Wildfires?

A. The 2020 WM Plan included only one PSPS zone (Mt. Hood). Following the 2020 Labor Day Wildfires, the 2021 WM Plan expanded to include the addition of six new PSPS zones and the slight expansion of the Mt. Hood zone (Zone 1).[7] The zones are identified as:

[7] See PGE Exhibit 810, page 18 for a map of 2021 PGE PSPS Zones

- PSPS Zone 1: Mt. Hood Corridor/Foothills
- PSPS Zone 2: Columbia River Gorge
- PSPS Zone 3: Oregon City - S. Redland
- PSPS Zone 4: Estacada - Faraday
- PSPS Zone 5: Scott's Mills
- PSPS Zone 6: Portland West Hills
- PSPS Zone 7: Tualatin Mountains

PGE is engaging in an ongoing effort to be aggressively proactive in our preparation for the 2021 fire season, which has resulted in the significant expansion from one to seven PSPS areas. We expanded to seven PSPS zones in the 2021 WM Plan because PGE's wildfire risk assessments and analyses indicate that these zones are areas of our service territory where vegetation, terrain, and wildland-urban interface infiltration increase the risk of utility-caused wildfire ignition. The expansion of these zones includes annual inspection of 100 percent of the assets in all seven PSPS zones. The 2021 WM Plan also addresses the supplementary proactive inspections and vegetation management that need to occur in these areas, which results in additional O&M and capital funding needed to support these activities.

Q. Please describe how PGE's WM Program aligns with its other emergency preparedness programs.

A. PGE approaches emergencies with all hazards in mind. PGE created the Corporate Emergency Operations Plan that supports several approaches to responding to unexpected events ranging from winter storms to a pandemic (e.g., the COVID-19 pandemic). PGE's incident management process is based on the National Incident Management System (NIMS). NIMS is the same system that many, if not all, first responders' incident management processes are based on. Using similar incident management processes that are based on NIMS allows for clearer communication and faster actions in responding to an event. PGE's response to a wildfire event will utilize the very same structure.

PGE's WM efforts are divided into three primary categories: Prevention, Detection, and Response. Prevention activities use risk analysis to make informed decisions on where to invest in system hardening, conduct enhanced vegetation management, conduct inspection work, and identify PSPS areas. Detection work is focused on installing weather stations, FirstAlert cameras, as well as evaluating technology that can provide intelligence on system performance to enhance our situational awareness. Response relates to executing our emergency plan during a PSPS event and launching the Corporate Incident Management Team as directed in the Corporate Emergency Operations Plan. Our WM Plan is based on continuous learning and is updated annually.

Q. Have other utilities in the United States created or planned to create a WM plan?

A. Yes. Utilities in California and Nevada have created WM plans or natural disaster plans that are provided to their respective utility commissions. In addition, many utilities in the west are in various stages of developing WM plans and strategies.

Q. What lessons has PGE learned from working with utilities whose WM plans are more matured?

A. Over the past two years, PGE has worked with utilities in California and the Northwest, industry groups such as Edison Electric Institute and Western Energy Institute, academic institutions, vendors and partners within local, state, and federal governments on WM plan best practices and lessons learned. PGE also joined the International Wildfire Risk Mitigation Consortium. One common theme is that there is no one-size-fits-all approach to WM as each utility's service territory varies and will have different fire risks and characteristics that will require different activities within the WM Plan. However, PGE has identified significant lessons/best practices related to core sections of WM plans, which include fire risk assessment and modeling, design and construction, and situational and conditional awareness.

As another example, The California Public Utilities Commission has identified priority improvement areas for PG&E as:

- Public/private sector coordination;
- Accuracy and availability of maps;
- Scaling response for event;
- Decision-making for emergencies;
- Restoration and mutual assistance;
- On-call resources and consultants; and
- Minimizing scope of PSPS events.

While PGE has a smaller footprint, it has similar risks of wildfire due to similar variables and circumstances as the utilities in California, such as changing climate conditions and heavily forested areas.

Q. Has PGE assessed its WM capabilities? If so, please describe the assessment.

A. Yes. Given the increased number of wildfire events throughout the Western United States over the last few years, PGE has a critical role in reducing the risk of wildfires caused by electrical equipment or maintenance activities and is approaching this issue with urgency. PGE assessed its WM capabilities based on our fire risk modeling and what other utilities in the industry are doing to reduce their identified wildfire risk. From the assessment, PGE developed the WM Plan. The assessment identified areas of our service territory, as well as areas where we have transmission and generation facilities outside our service territory, with elevated fire risk. The assessment helped inform what we need to develop and implement as a part of a WM Plan.

Q. What portions of PGE's service territory are at the highest risk for wildfires?

A. PGE has initiated an enterprise-wide, phased approach to assess, as well as mitigate, wildfire risk. In Phase 1, PGE used publicly available data to provide interim risk-based guidance for decision-making in the 2019 and 2020 fire seasons. To the extent possible and practical, we also leveraged the approach developed by California-based electric utilities to identify areas of Elevated (Tier 2) and Extreme (Tier 3) wildfire risk within PGE's service territory, surrounding generation assets, and along owned and operated transmission corridors. This analysis yielded portions of elevated risk within PGE's service territory in and around the Mt. Hood National Forest on the north and south sides of Highway 26 from Alder Creek to Government Camp. Areas of elevated and extreme risk were also identified outside of PGE's service territory, specifically transmission facilities in or around the cities of Warm Springs, Madras, Redmond, and Prineville; and a generation facility east of The Dalles.

In Phase 2, PGE modeled the annual utility wildfire risk associated with T&D equipment, which will be used in evaluating the potential reduction in utility wildfire risk that may be realized by interventions. Phase 2 efforts will support decision-making during and after the 2021 fire season which may include the expansion of PSPS locations.

In Phase 3, which will be completed in 2021, PGE will enhance our analysis by determining how the components of risk vary with changes in weather, such as high winds and low humidity. The resulting outputs will better enable PGE to make operational decisions in real-time, such as implementation of a PSPS.

Q. What is Advanced Wildfire Risk Reduction (AWRR)?

A. AWRR is a new vegetation management program that will serve to reduce the risk of wildfire associated with vegetation near utility assets. AWRR is a part of the WM Plan and will focus its efforts initially on vegetation in all seven PSPS zones. AWRR will include annual inspections of all PSPS mileage, followed by hotspot trimming, which is trimming of vegetation within five feet of PSPS feeders. AWRR also contains annual identification and mitigation of "P1" Hazard/Danger Trees and "P2" Trees, which are non-hazard/danger, but exhibit articulable arboricultural defects and are within fall-in/overstrike proximity to PGE's overhead assets. For more details on AWRR, please see Section 7.2 of the WM Plan included as PGE Exhibit 810.

Q. When did PGE begin these activities and why is it important to engage in these activities at this time?

A. PGE first began a form of AWRR in 2019, but officially created and began work under the AWRR Program in 2020, operating exclusively within Tier 2 and Tier 3 risk zones previously identified by PGE (Mt. Hood corridor). The official AWRR Program expands upon our prior efforts to reduce the risk associated with wildfire. Encroaching vegetation is a leading source of wildfires ignited by the electrical grid, therefore establishing a program within the WM Plan is a key element of our wildfire preparedness efforts. Additionally, the expansion of the PSPS zones from one to seven, since last year, results in a corresponding aggressive expansion of the AWRR Program due to increased line mileage needed to be inspected and scoped for trimming and removal in accordance with our AWRR scope and best-management practices. These activities are crucial to protect our customers and reduce wildfire risk associated with PGE assets in our high-risk areas (PSPS Zones).

Q. Is PGE requesting additional funding in this GRC for AWRR?

A. Yes, however, due to the aggressive expansion of this work, PGE is taking a phased approach to implementation and has only included funding for the 2022 test year in this GRC. The funding request is identified in Section VI on vegetation management. While these activities directly relate to our WM Plan, the expenses are a part of the vegetation management budget.

Q. Please describe the actions that PGE has taken since its last GRC to improve its other WM capabilities.

A. Since the last GRC, we developed the WM Plan and we are continuing to refine tools and processes to improve our WM capabilities. We have performed benchmarking with PG&E, SDG&E, and SCE in a variety of areas, including risk assessment, meteorology, operational processes, inspection cycles, emergency response, restoration, communications, and customer support. In addition to creating a WM Plan, PGE created a WM Program, which includes the dedicated resources responsible for developing the WM Plan, and we added new tools to increase awareness and understanding of wildfire risk and danger, including our ArcGIS Online Wildfire Threat Viewer, in part, as a result of our benchmarking.

Q. What is your WM request within this GRC?

A. As discussed, PGE has significantly increased its WM efforts to address the increased threat of damage caused by wildfires. To accomplish our goals and protect our customers, we are proposing $6.6 million for WM O&M, which is $4.6 million more than actual 2020 spending. We are also proposing $6.0 million for capital projects that will be placed into service by April 30, 2022.

The total O&M expense includes ten new positions, plus one transfer to Wildfire Operations from Business Continuity and Emergency Management. PGE established the

Wildfire Mitigation & Resiliency department in November 2020 following the Labor Day Wildfires that impacted Oregon. The current wildfire division consists of four existing personnel plus the existing BCEM division, which was established in 2007 to strengthen capacities and capabilities for the preparation, mitigation, and response to significant emergency incidents, including wildfires (see PGE Exhibit 400 for additional detail regarding the BCEM division). The new wildfire team will include six Program Managers, one Compliance Analyst, one Planner, one Risk Analyst, one Meteorologist, one Data Engineer/Analyst and one Program Engineer. However, not all the positions are incremental, as there are four existing personnel.

The capital projects include replacing poles and cross-arms with fire resistant versions, installing Viper reclosers[8] in PSPS zones, and purchasing and installing monitoring technology.

Q. Why is this the right time to increase the spending associated with WM?

A. In recent years, we have seen an increasing number of wildfire events in California, Oregon, and Washington. They have not only increased in number, but also in magnitude as 2021 fire season has been declared in mid-May east of the Cascades, and in mid-June west of the Cascades. These two declarations are earlier when compared to 2020 and could be a trend in future years. The damage sustained already by these fires has been substantial, as evidenced by the 2020 Labor Day Wildfires. The Governor's executive orders and the Special Wildfire Council have signaled that urgency is needed to address and prevent wildfires. These efforts and events have occurred within the past two years as PGE has been building its WM capabilities, program, and plan.

[8] Viper reclosers are electronically controlled vacuum fault interrupters that provide automatic or manual trip operations for overcurrent protection and isolation.

Q. What processes did PGE use to develop the cost estimate for the 2021/2022 and on-going WM efforts?

A. PGE conducted comprehensive benchmarking with other utilities and reviewed the regulatory requirements in California and Nevada. In addition, we anticipate that more requirements will be forthcoming from the OPUC wildfire rule making process (AR 638) and state and federal legislation.

Q. What cost control measures has, or will, PGE employ during implementation of its WM Plan?

A. As stated previously, PGE is developing a utility wildfire risk model to evaluate proposed wildfire mitigations that deliver good customer value and allow PGE to better target mitigations and potential de-energization of specific T&D lines to reduce wildfire risk. Specifically, the model is being developed to approximate utility-specific wildfire risk (Utility Wildfire Risk = Probability multiplied by Consequence), integrate consideration of utility wildfire risk into PGE's asset management and other decision-support processes, and support the business case for prudent investments to mitigate wildfire risk. PGE teams will use this analysis to approximate the annual utility wildfire risk associated with T&D structures and equipment, and to evaluate the potential reduction in utility wildfire risk that may be realized by prudent investments.

Q. Please describe the actions that PGE has taken to begin implementing its WM Plan.

A. PGE teams have completed enhanced vegetation management and annual WM detailed inspections of all transmission structures and distribution poles located in Tier 2 or Tier 3 wildfire risk areas, based our 2019 wildfire risk assessment:

- Overhead transmission and sub-transmission circuit miles

    - 34 miles (2% of total circuit miles) in Tier 3
    - 66 miles (4% of total circuit miles) in Tier 2
- Overhead distribution circuit miles
    - One mile (0.01% of total circuit miles) in Tier 3
    - 99 miles (1% of total circuit miles) in Tier 2
- Zero customers in Tier 3; and
- 4,248 customers in Tier 2.

Q. Please describe PGE's plan to continue to develop its WM capabilities.

A. For the next several years, PGE will focus on maturing our WM capabilities to effectively reduce potential ignitions, increase access to real-time weather observations and/or forecasts, refine the boundaries of high fire risk and PSPS zones, and harden the PGE assets to survive or reduce damage caused by wildfires. In July 2020, PGE completed Phase 2 development of our utility wildfire risk model. This model details the likelihood of discrete transmission or distribution assets acting as a potential source of ignition, and the consequences of ignition, based on Pyrologix data, to calculate the wildfire risk on individual T&D lines and structures. This risk-based approach will enable evaluation of proposed WM efforts that deliver exceptional customer value and allow PGE to better target mitigations and potential de-energization of specific T&D lines to reduce wildfire risk.

Q. Please summarize your testimony on wildfire mitigation.

A. Because of the increasing threat of wildfires and impact on people, property, electric service and the environment, PGE separated its WM efforts from its vegetation management program, combined WM with the BCEM program, and created a new WM Program in November 2020. Like other utilities in the region, PGE is continuing to develop and implement its WM Plan, which was developed by members of the WM Program, by adding ten new employees and hiring experts to assist in developing our WM Program. PGE expects to spend $6.6 million in O&M on WM in 2022, a $4.6 million increase from 2020 levels. We also expect to place $6.0 million of capital for WM into service by April 30, 2022.

VI. Vegetation Management

Q. Please describe PGE's vegetation management (VM) program.

A. PGE's VM program is comprised of five elements: 1) Line-clearance tree trimming (routine maintenance); 2) PGE FITNES and Capital support; 3) Outage and storm response; 4) Enhanced Vegetation Management (EVM); and 5) AWRR.

Line-clearance tree trimming is the routine maintenance that PGE conducts to control vegetation in the right of way (ROW) in accordance with OPUC Division 24 Clearance rules. Due to climate change impacts, the growing season is longer resulting in a two-year trimming cycle in some places in lieu of three-year cycles of the past. PGE FITNES and Capital is VM work that is performed in support of PGE construction, maintenance, or repair projects (i.e., pole replacements, reconductors, transformer replacement, new line construction, etc.). Outage and storm response is the management of vegetation during a wind, ice, or snow storm, or other major outage events as needed. This work may occur at any time of the day or night and is supported by on-call, dispatched, VM staff and tree crews. EVM is a new program that will focus exclusively on reliability risk by targeting the vegetation types that contribute significantly toward PGE outage events. Finally, AWRR, as described in Section V, is a proactive VM strategy that occurs specifically in PSPS zones.

Q. What are the incremental VM costs for 2022 compared to 2020?

A. VM O&M costs in 2020 were $26.1 million, which was $4 million less than budgeted due to the impacts of the COVID pandemic. VM O&M costs for 2022 are projected to be $48.7 million, which is an increase of $22.6 million.

This increase is being driven primarily by:

- Changes in forestry-based activities and updates to our line-clearance tree trimming program results in an increase of $5.6 million.
- EVM is a new program that represents $4.2 million of the increase; and
- AWRR, as described above in Section V on wildfire mitigation, represents a $12.8 million increase.

Q. Please describe the updates PGE is making to its line-clearance tree trimming program.

A. The work that PGE customers are most familiar with is managing the over-head powerline vegetation clearances through planned tree trimming or removal operations. PGE has implemented an improvement initiative to evaluate and strategically adjust trim cycles to deliver maximum compliance and reliability results for PGE customers. PGE's system is currently split between 2-year and 3-year trim cycles. Through integrating a data-driven approach PGE can work toward providing the foundational, compliance-based, public safety benefits while also enhancing system reliability.

Q. Why are you making this transition and what benefits will this provide to customers?

A. We are making this transition as a result of climate change in Oregon. Assessing our trim cycles, combined with appropriate trim specifications, will provide PGE the maximum OPUC Division 24 compliance benefit. Our current cycle timing in some places is no longer sufficient given the impacts of climate change over the last decade (or more) that have resulted in longer growing seasons. Another benefit of this initiative is that it provides the maximum reliability benefit that can be achieved exclusively through routine line clearance tree trimming. Data collected through the 2019 and 2020 OPUC Vegetation Audit[9] revealed that PGE could anticipate a significant reduction in probable violations through the

[9] PGE Exhibit 811

implementation of this initiative. Overall, the benefits of moving to a process actively focused on determining appropriate trim cycles result in improved compliance performance with NESC standards and OPUC Division 24 Clearance Standards for safety, and an improvement in reliability with fewer service disruptions.

Q. How did PGE determine the cost increase associated with this transition and on what basis did you determine this cost to be reasonable?

A. We determined the cost as a balance between the pace at which we could perform an assessment, achieve faster trim cycles in certain areas and a reasonable cost to get there. If we assess and transition too slowly, our ability to achieve a new cycle will be constrained by continued increase in biomass and vegetation growth that is always actively occurring with the tree population that PGE manages. Assessing and transitioning too quickly would not only be cost prohibitive, but the ability to conduct the work that is needed would be constrained by our ability to obtain appropriately trained and experienced crews needed to do the work safely and in a cost-efficient and productive manner.[10]

Q. What is EVM and what is the benefit of EVM for customers?

A. EVM is a new program that will be implemented in 2022. EVM focuses exclusively on reliability risk by targeting the vegetation types that contribute significantly to PGE outage events. Vegetation-caused outages amount to 48% of all outages, and Off-ROW and/or beyond maintenance standard vegetation failure accounts for approximately 96% of the vegetation-caused outages.[11] Our GIS-based outage tracker and historical data have identified the failure profiles of the most common tree species in our service territory. Using real-time data analytics (Light Detection and Ranging, OMS, and GIS), we coordinate with our

[10] See PGE Exhibit 812, showing crew levels since 2015.
[11] See PGE Exhibit 813, cells D4 and E4 on the Totals tab.

Strategic Asset Management (SAM) team to target activities to achieve reliability benefits by using prescriptive, and more intrusive, tree trimming/removal efforts. Examples of this type of programming include, but are not limited to, tree removal, tree-part removal, shelf/overhang removal, and crown reduction

This benefits our customers by strategically eliminating the most common drivers of vegetation-related outages throughout PGE's service area. As PGE implements the EVM programming, our customers will see reduced impacts to their electrical service and power quality.

Q. Please explain the cost increase associated with AWRR.

A. As described in Section V, PGE has taken an aggressive approach to wildfire mitigation with VM being a crucial component in high-risk wildfire areas and will be phased in over the next several years. However, the increase shown above for AWRR represents only the 2022 test year increases and are estimated as a new program to meet best known industry practices in the current PSPS areas. This program will be coordinated with the standard VM, FITNES and Capital, and EVM programs.

Q. Are there other contributing factors to the three cost increases discussed above?

A. Yes. We have modified our practices to make safety-driven changes. For example, these changes have resulted in an increase in outside services costs for multiple setups of bucket trucks to implement safer work practices. Tree trimming productivity has also decreased due to an increase in municipal restrictions, such as more stringent permitting requirements, work hour restrictions, and flagging restrictions. This has led to additional work for current resources as foresters need to obtain and negotiate permits and set up traffic controls to meet additional municipal requirements that are not standard across the 51 municipalities in PGE's service territory.[12] Labor costs have also increased per union contracts as tree trimming crews are represented by International Brotherhood of Electrical Workers (IBEW) Local 125. These negotiations occur between IBEW Local 125 and Line-Clearance contractors every few years, similar to IBEW Local 125 negotiating with PGE regarding line operations.

Q. Is there anything else driving the increases in VM?

A. Yes, in addition to the programmatic needs discussed above, the increase in VM work is also driven by extended growing seasons as a result of global warming, increased volume of PGE work orders due to customer growth within PGE's service territory, increased volume of PGE FITNES Program work orders, and increased number of PGE customer requests. To successfully implement these ongoing programs and achieve improved reliability and system resilience for customers, PGE needs to increase its VM staff. Specifically, we will be adding eight Regional Foresters, two Resource Schedulers, one AWRR Supervisor, one Landscape Specialist, and one Operations Analyst.

Q. Please summarize your Vegetation Management testimony.

A. Elements of the VM Program are continuing to expand to achieve compliance and support improved reliability. The program enhancements described above include implementing an initiative to evaluate and strategically adjust tree trimming cycles, modifying our practices to make safety-driven changes, creating a new reliability program (EVM) and expanding our AWRR Program. EVM focuses exclusively on reliability risk by targeting the vegetation types that contribute significantly toward PGE outage events, and AWRR is an important initiative to supporting our wildfire mitigation efforts.

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[12] See PGE Exhibit 814, PGE Exhibit 815 and Chapters 51 and 55 of the Lake Oswego, Oregon code for examples of municipal requirements. See link: https://www.codepublishing.com/OR/LakeOswego/.

To increase our VM capabilities, PGE seeks VM O&M costs of $46.7 million in this case, an increase of $22.6 million from 2020 to 2022.

VII. Level III Outage Restoration

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;[13] or
- Renders several substations and feeders out of service.

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

A. Yes. The years 2014 through 2017 witnessed numerous significant Level III events and led to the accrual being increased from $2.0 million in PGE's 2016 GRC (Docket No. UE 294) to approximately $3.7 million in PGE's 2019 GRC (Docket No. UE 335). In 2018 through 2020, we experienced fewer and less damaging events, but in January and February 2021, PGE experienced two significant events, which we included in the proposed accrual.[14] Consequently, the current ten-year moving average increases by approximately $6.6 million

[13] An IEEE Major Event Day exclusion is a day in which our daily System Average Interruption Duration Index (SAIDI) exceeds a threshold value. In 2017, the T_{med} was 4.84 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.

[14] Because PGE has filed for a deferral in relation to the February event (Docket No. UM 2156), the 2022 accrual can be updated, if applicable, based on the UM 2156 determination.

resulting in an updated annual accrual of approximately $10.4 million.[15] This increase is summarized in PGE Exhibit 816 and is primarily driven by the February 2021 ice storm emergency, which we discuss further below.

Q. Does your ten-year moving average include PGE's restoration costs associated with the 2020 Labor Day Wildfire Event?

A. No. Because of the extreme nature of this event, PGE filed for and received approval to separately defer the incremental costs associated with the Labor Day wildfire emergency (Commission Order No. 20-329; Docket No. UM 2115). Consequently, we have not applied those costs to the Level III reserve account or the 10-year moving average.

Q. Does the reserve account absorb all costs associated with Level III restoration?

A. No. The reserve only absorbs costs to the extent that the account has a positive balance. If restoration costs exceed the reserve balance, shareholders absorb those costs because the reserve account cannot be negative.

Q. Has PGE proposed a modification to this mechanism in a previous GRC?

A. Yes. In PGE's prior GRC (Docket No. UE 335), PGE proposed that the Level III reserve be converted into a symmetrical balancing account so that it can have negative as well as positive balances and allow PGE to apply all Level III restoration costs to it.

Q. How did the Commission respond to this proposal?

A. The Commission denied PGE's request but invited us "to return with an alternative that provides more justification, and a chain of causation justifying the change."[16] The Commission also noted that "PGE must explain and discuss the allocation of risks with customers and company incentives for developing a more resilient system that requires less

[15] Restoration efforts for the ice storm emergency are continuing so that these costs are not yet final.
[16] Commission Order No. 18-464, page 14.

expense to recover from Level III storms."[17] In later rejecting a deferred accounting petition for PGE's extraordinary storm costs in Order No. 19-247 (Docket No. UM 1817), the Commission reiterated this direction:[18]

> We have previously stated that, in evaluating any future storm recovery mechanism, the Commission expects a holistic plan that balances recovery of costs from more frequent high-impact events with incentives for investments and practices that mitigate the negative consequences from those events. Specifically, in proposing any future alternate storm mechanism that would increase the company's recovery of Level III storm costs, we directed PGE to fully address the allocation of risk with customers and company incentives for developing a more resilient system. In the company's next rate case, we are prepared to consider how to appropriately allocate the risk associated with the cumulative effect of multiple years of above-average storm costs as well.

Q. Do you have a new proposal in this GRC and are you prepared to address the Commission's requests?

A. Yes. We have a new proposal and will address all the issues specified above.

Q. Please describe your proposal to modify the Level III mechanism.

A. PGE's proposed mechanism is as follows. The amount collected in base prices will continue to be based on the ten-year average of Level III restoration costs, which will accrue to a reserve account for use against future Level III events. If Level III restoration costs in a given year exceed a positive reserve balance, the reserve account will allow a negative balance to be maintained until a positive balance is restored by collections exceeding costs based on the following criteria:

- For every year that results in a negative balance, the actual Level III restoration

[17] Ibid.
[18] Commission Order No. 19-274, pages 13-14

costs that are applied to that negative balance[19] will be shared 90% by customers and 10% by PGE (i.e., 90/10 sharing, where 90% of the costs will be applied to the balancing account and 10% will be absorbed by PGE).

- If the balancing account exceeds a $12 million positive or negative balance, PGE will amortize the excess amount by either collection from (negative balance) or refund to (positive balance) customers based on a 90/10 sharing of the excess amount.

Q. You stated previously that PGE did not apply its Labor Day wildfire costs to the 10-year moving average or the Level III reserve, but PGE has included the February 2021 ice storm, subject to the resolution of PGE's UM 2156 deferral application. How does PGE define the types of events that would apply to the current and proposed Level III reserve mechanism?

A. PGE believes that basic Level III outage events should apply to the current and proposed reserve mechanism and be used to update the 10-year moving average for the annual accrual. Events that are more extreme in nature, however, and as defined by a declared state of emergency, should be covered by alternative cost-recovery, such as an emergency deferral. From March 2020 through February 2021, PGE experienced three declared states of emergency – two related to outage events (i.e., the wildfire emergency and ice storm emergency) and the third related to the COVID-19 emergency.

This unprecedented series of events suggests that an alternative mechanism is warranted and we noted as such on page 3 of PGE's clarified UM 2115 wildfire outage deferral

[19] If the Level III restoration costs exceed a positive reserve balance, only the costs that are applied to the negative balance will be subject to the sharing. The costs that take the balance to zero will not be subject to sharing. If the balance is already negative, all Level III restoration costs will be subject to the sharing percentages.

application: "PGE believes that a more comprehensive mechanism to address a wider range of significant events and system emergencies is necessary. However, because such a mechanism is not currently available, PGE proposes to not apply the wildfire emergency costs to the Level III outage reserve."

Q. Do you have a specific proposal for regulatory treatment of emergency events?

A. Not at this time because of the following:

- The COVID-19 emergency occurred first and began in March 2020. Regulatory treatment of COVID-19-related costs was resolved by a stipulation among numerous parties and adopted by Commission Order No. 20-324 (Docket UM 2114). This allowed PGE to defer incremental costs associated with the emergency as filed under Docket No. UM 2064 (also approved by Commission Order No. 20-376).
- The Labor Day Wildfire emergency occurred next in September 2020. Because of the extreme nature of the event, which began as an unprecedented summer wind event, PGE filed the UM 2115 deferral as referenced above and Commission Order No. 20-389 approved deferral of the associated costs.
- The Ice Storm emergency then occurred in February 2021. It was the third emergency in one year, unprecedented in the number of outages and scale of damage to our system, and significantly more costly than the prior two emergencies. To address this, PGE filed for a deferral in Docket No. UM 2156. That docket is still pending.

In short, emergency events have recently occurred so rapidly that developing and proposing an alternative mechanism has not been practicable. That is why PGE left the issue open in our UM 2156 filing by noting on page 3 that "PGE intends to discuss with the OPUC Staff and others the appropriate application, if any, of the Level III outage mechanism for later determination by the Commission as well as the use of a new deferral account to supplement or replace the Level III outage mechanism."[20] We also understand that the Commission has been informally reviewing how to handle emergency deferrals given the increased frequency of major outage events.

Q. How otherwise does your current Level III mechanism proposal address the factors the Commission ordered PGE to address when proposing a new Level III mechanism?[21]

A. We address each of the factors raised by the Commission in the following sections that follow.

A. Impacts of Climate Change

Q. Please describe the first factor regarding the chain of causation.

A. The first factor the Commission ordered PGE to address is the chain of causation, for which the Commission stated "Any request for an alternative Level III storm deferral mechanism based, in part, on claims of greater storm intensity due to climate change, however, should include some foundational analysis to justify this claim, and provide a chain of causation that connects evidence of expected increases in storm frequency and intensity to increased costs."[22]

Q. Is your proposal based on a claim of greater storm activity and associated higher costs?

A. Yes, as well as additional relevant aspects. When Commission Order No. 10-478 first approved PGE's Level III recovery mechanism, it was originally viewed as relating to storms,

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[20] *PGE's Application for Authorization to Defer Emergency Restoration Costs*, Docket No. UM 2156 (Feb. 15, 2021).
[21] *See* Commission Order No. 18-464 at 14.
[22] Ibid.

or more specifically, winter storms. These have indeed increased. To be more precise, however, Level III outages can occur at any time the criteria are met and can occur in any season due to extreme conditions. While winter storms have typically been the most common type of Level III event, we are witnessing a greater variety of events and events with greater intensity than were contemplated in Docket UE 215.

Q. Do you have any examples of this?

A. Yes, two recent examples involve non-winter wind events. In 2017, when PGE experienced a significant amount of Level III outage restoration costs, one of those events was a spring wind event. More recently in 2020, the Labor Day wildfire emergency was primarily driven by an unprecedented summer wind event. We even incurred a micro-burst that collapsed 500 kV towers near the town of Madras, Oregon.

Q. Do you have any evidence that climate change is affecting, or will affect, your Level III restoration costs going forward?

A. Yes. The Fourth National Climate Assessment[23] has identified the following expected impacts from climate change on the Pacific Northwest:

- "Strong climate variability is likely to persist for the Northwest, owing in part to the year-to-year and decade-to-decade climate variability associated with the Pacific Ocean. Periods of prolonged drought are projected to be interspersed with years featuring heavy rainfall driven by powerful atmospheric rivers and strong El Niño winters associated with storm surge, large waves, and coastal erosion."[24]
- "The Northwest is projected to continue to warm during all seasons under all future scenarios, although the rate of warming depends on current and future emissions.

[23] Fourth National Climate Assessment, Chapter 24, at https://nca2018.globalchange.gov/chapter/24/.
[24] Fourth National Climate Assessment, Chapter 24, Executive Summary.

The warming trend is projected to be accentuated in certain mountain areas in late winter and spring, further exacerbating snowpack loss and increasing the risk for insect infestations and wildfires."[25]

- "Years of abnormally low precipitation and extended drought conditions are expected to occur throughout the century, and extreme events, like heavy rainfall associated with atmospheric rivers, are also anticipated to occur more often."[26]

In summary, these projections mean that although there might not be greater likelihood of traditional winter snowstorms, there is an increasing likelihood of high wind and rain events plus greater risk of wildfires. Recent events also indicate that extreme winter storm events continue to be a very real possibility.

B. Allocation of Risks

Q. In what way does your proposed mechanism address the allocation of risks?

A. Because the Commission did not agree with PGE's previous proposal for a symmetrical balancing account that would effectively allow PGE full recovery of all costs associated with Level III outage restoration, we understood this to mean that a subsequent proposal should be based on a sharing of costs between customers and shareholders. To address this, we have incorporated two forms of sharing in the proposed mechanism. First, all Level III restoration costs that are applied to a negative balance would be shared 90% by customers and 10% by shareholders. Second, to avoid the reserve balance becoming too large by either too mild or too extreme conditions, we propose that if the reserve account were to exceed $12 million

[25] Fourth National Climate Assessment, Chapter 24, Background
[26] Fourth National Climate Assessment, Chapter 24, Background

(positive or negative), it would be amortized by either collection from (negative balance) or refund to (positive balance) customers based on a 90/10 sharing of the excess amount.

Q. Will this level of sharing impact how PGE manages its costs when responding to Level III events?

A. No. When Level III events occur, PGE makes every effort to restore power as quickly as possible. This is expected of us by customers, by the Commission, and by ourselves. PGE has always maintained this commitment and will continue to do so, regardless of how some or all of those costs are recovered. For example, over 1,000 field workers and support personnel were deployed during our April 2017, Level III wind event to restore service for approximately 185,000 customers who were without power at the peak of the event, and we did so even though the reserve had already been depleted by a prior Level III event in January 2017. More recently, PGE incurred approximately $67.9 million during the February 2021 event to restore power to over 420,000 customers, more than 100,000 of whom experienced multiple outages – some up to six. This cost was significantly greater than the available Level III reserve.

In addition, PGE manages its restoration efforts to be efficient and effective, but with the primary commitment of restoring service as quickly and safely as possible. In other words, PGE does not and would not engage in limiting its Level III-related costs by delaying restoration to incur significantly less overtime and contractor hours. Conversely, PGE has no incentive to over-apply resources and costs to a Level III event.

Q. Please elaborate.

A. When PGE commits resources to Level III events, we must postpone other scheduled T&D activities. The more Level III events PGE experiences or the more resources we must apply to respond to those events, the more work we have to postpone. Because the postponed work is important for reliability purposes, PGE will then have to incur additional costs to complete those tasks prior to: 1) summer before peak loads occur;[27] or 2) the next winter, when weather limits this type of work. This means that even if PGE were to have full recovery of all Level III restoration costs, our actual T&D O&M costs would increase during a year with significant Level III events. Consequently, PGE has no incentive to over-apply resources or costs to Level III events.

Q. Why, then, do you believe this is the correct level of sharing?

A. Ultimately, PGE continues to believe that Level III restoration costs are prudently incurred to support public safety and welfare, and to meet customers' increasing reliability expectations, and they should be recoverable. The Commission Staff (Staff) and other parties, however, have argued that with full recovery, PGE would have a disincentive to effectively manage its Level III restoration costs.[28] We disagree, as noted above, and believe that the historical evidence of our commitment to service restoration speaks for itself. To resolve this, we also believe that 90/10 sharing percentages within the proposed mechanism represent a reasonable compromise to satisfy Staff's and parties' concern but also to provide PGE more recovery than the current mechanism, which is notably asymmetrical with respect to risk and reward for PGE shareholders.

[27] In these cases, PGE will incur costs to implement reliability upgrades to mitigate certain loading conditions on our system.
[28] See Docket No. UE 335 and/or UM 1817.

C. Mitigation of Risks

Q. How do you address the Commission's third factor regarding company incentives for developing a more resilient system that requires less expense to recover from Level III events?

A. As noted above, PGE is committed to restore power to customers as quickly as possible under all situations, which tend to be particularly arduous under Level III conditions. This activity is a core utility function in service to our customers and we have established specific corporate goals to meet customer satisfaction levels and system reliability targets. As part of that commitment, PGE is also proactively investing in its infrastructure to mitigate the impact of Level III event damage before it occurs but also to enhance the resilience and reliability of the T&D system as discussed in Sections IV, V, and VI, above. Further, we are doing so based on a rational approach and without regard to the mechanism under which Level III restoration costs are recovered. In other words, a change in the mechanism will create neither an incentive nor disincentive to continue this work.

Q. Please describe how this work is being performed in a rational manner.

A. PGE employs a proactive asset management strategy to reduce risk. A key component of this effort is the SAM department, which prepares an annual T&D risk assessment and associated portfolio of recommended risk reduction projects. The SAM department accomplishes this through a risk assessment method that employs industry best practices criteria to quantify threats to the grid and evaluate the impacts to customers should portions of the system fail. SAM's risk assessment approach encourages a long-term plan that cost-effectively reduces risks (including reliability, safety, and environmental) and supports customer needs.

Q. Please briefly describe the risk assessment method.

A. SAM identifies system improvements that demonstrate maximum value to customers in terms of risk reduction. This is accomplished by quantifying the existing risk associated with specific assets or geographic regions as well as the potential benefit of system improvements (i.e., increased operational efficiency) to determine optimal investment in infrastructure. Risk is calculated using both the likelihood of asset failure or environmental impact *and* the consequences of that event. The consequences of asset failure or environmental impact are determined using a detailed grid connectivity model, enabling PGE to prioritize investments based upon specific customer and grid impacts. This is a rigorous process based on quantified risks and benefits to customers and would not be disincentivized or otherwise impacted by cost recovery for Level III events.

Q. What proactive, SAM-based investment relates to mitigating Level III restoration risk?

A. To address Level III mitigation, we consider non-asset risk as opposed to asset risk. Asset risk is associated with the electrical infrastructure that serves customers. This type of risk is more predictable and accounts for approximately one-third of annual outages. Non-asset risk is associated with external, geographic factors that impact electrical infrastructure, and thus service to customers. Examples include weather, vegetation, animal contact, and vehicles hitting power-line poles and account for approximately two-thirds of all outages. To cost-effectively mitigate these risks, SAM considers the potential for outages and solutions to limit the occurrence and/or extent of an outage event, if it were to occur. The following are examples of efforts evaluated annually to mitigate non-asset risk related to weather:

- Transitioning overhead conductor to underground conductor is a very effective but costly method of mitigating storm risk, so it is used in limited circumstances. The effectiveness of this method, however, is observable in fully undergrounded downtown Portland, where reliability is near 100%.

- System hardening with tree wire and ductile iron poles is effective in areas with significant tree growth in the vicinity of wires and high wildfire danger areas. Where cost-effective to do so, PGE will install tree wire (i.e., conductor covered with insulation). This will limit the potential for an outage when tree limbs contact the wire during wind, snow, and/or ice storms.
- Vegetation management is applied throughout PGE's service territory but is more pronounced in certain corridors where additional effort is justified. This is a particularly important aspect of our wildfire mitigation efforts as discussed in Section V of this testimony.
- FLISR schemes are installed to detect, isolate, and restore power to more customers in an automated, in lieu of manual, fashion. Significantly less response and restoration efforts are required with this functionality, thus reducing outage durations for customers on circuits equipped with this type of DA equipment.
- Trip Savers are "smart" fuses that are deployed in place of traditional, standard fuses at tap lines. These devices help avoid sustained outage events, shorten outage durations, and/or reduce the number of customers impacted by an outage event.

Q. Have the recent emergencies impacted your thinking regarding T&D investments?

A. Yes. The ice storm emergency in February 2021, in particular, was the most extreme and impactful event that PGE and our customers have experienced since the Columbus Day storm of 1962. The sheer extent of damage to PGE's facilities and the associated outages highlights how crucial it is for continued and even accelerated investment in our T&D facilities to enhance system reliability and resiliency. Consequently, we will continue to evaluate how to improve our system's ability to survive such an event, and how to recover from it more quickly. Finally, we will apply those learnings to our BCEM and wildfire mitigation plans going forward.

The ice storm emergency also highlighted how critical it is to have effective communication and coordination within PGE, with our customers, municipalities, and with state and local leaders/agencies prior to, during, and following an event while restoration efforts are underway. Consequently, PGE launched a new outage website during the emergency that provided customers with a clearer picture of the extent of the outages and restoration efforts. The new outage website included information on current work in progress, restoration work completed to-date, a map showing how many crews were working and where they are working, a video showing the steps PGE takes when restoring power, what to do when the power goes out, important safety tips, and answers to frequently asked questions.

Since the wildfires of 2020, PGE has also been researching best practices among peer utilities on how they manage the intake of outage related data, organize it, and communicate it in the most coherent manner for their customers. Best practices point to setting up a group of employees in the control center who are trained to manage, collaborate, and organize the incoming data for all types and sizes of outages. The group will be staffed 24/7 and be the nexus for incoming data, interpretation, summarization and most importantly, managing accurate restoration times for affected customers. The goal is to hire and train this group of OCS employees to begin fulfilling this role in 2021 and working from within the IOC distribution control room by the end of 2021.

In addition, PGE is conducting a root cause investigation into the failure of a number of poles supporting our 57kV lines during the ice storm emergency to determine if the system performed as expected or if opportunities exist to improve performance given expectations of an increase in future storm impacts especially with ice accumulating at 1-2 inches. Based on that determination, we will evaluate the need to plan and design facilities to account for increased severe weather cases, including updated planning criteria, design and construction standards and materials.

Q. Please summarize why is it important for PGE to receive Commission approval to revise the Level III cost recovery mechanism.

A. The current mechanism limits PGE's ability to recover Level III restoration costs, which are incurred to provide safe and reliable power for our customers as quickly as possible during severe outage events. Commission approval for the proposed revisions would provide PGE with the opportunity to recover prudently incurred Level III restoration costs with a reasonable sharing of those costs between customers and shareholders. Although there are no specific predictions of how climate change will impact the number and severity of PGE's Level III events, growing evidence suggests that the nature of events is expanding to include a greater variety of causes over the entire year rather than just winter storms. Finally, recent experience, in particular, indicates that the existing mechanism is inadequate to address the number and severity of events that can and will occur.

VIII. Summary

Q. Please summarize your testimony.

A. PGE has undertaken a significant number of new T&D projects including a new IOC, an ADMS, and enhanced wildfire mitigation and vegetation management efforts to better serve our customers. These multi-year efforts are in addition to our ongoing efforts to replace aging infrastructure, additions to meet new large customer load, as well as constructing new facilities to satisfy the needs of our growing customer base and meet our NERC compliance obligations. All these efforts are a part of our grid modernization initiative to maintain and improve the reliability of our system, improve resilience, and improve visibility into our system, such as visibility into the state of the real-time system which will be provided by ADMS, all while keeping customers costs as low as possible.

These efforts will increase T&D O&M expense for 2022 by approximately $25.9 million compared to 2020 actuals of $146.7 million. The primary drivers of T&D O&M cost increases are grid modernization, wildfire mitigation, and vegetation management. PGE's total T&D additions to capital for 2019, 2020, 2021 and through April 2022 are $1,566 million, $215.2 million for the IOC, and $30.6 million for ADMS.

The IOC is the key element of PGE's grid modernization initiative and will allow PGE to maximize the benefits of its grid modernization initiative. The IOC will centralize all the mission critical operations that maintain the flow of power to customers, both during normal operating conditions and following a disaster, in a resilient facility that also provides the needed physical security.

PGE's ADMS program is a new program that is part of its grid modernization plan. ADMS supports prediction, monitoring, control, optimization, and safe operation of all elements within a distribution system.

Because of the increased threat of and impact on people, property, electric service and the environment from wildfires, PGE separated its wildfire mitigation efforts from its vegetation management and BCEM programs and created a new Wildfire Mitigation Program in 2019. PGE, like other utilities in the region, is continuing to develop and implement its Wildfire Mitigation Plan. To continue to develop our WM capabilities, PGE expects to spend $6.6 million in O&M on wildfire mitigation in 2022, which is an incremental $4.6 million compared to 2020.

PGE is strengthening its vegetation management program to achieve new reliability, resilience, and safety goals. To achieve these goals, while operating in an environment of increasing municipal requirements and increased costs for skilled labor, PGE's vegetation management O&M costs are projected to increase by $22.6 million from 2020 to 2022.

PGE proposes to modify its Level III mechanism to include a cost sharing mechanism between customers and shareholders. The amount collected in base prices will continue to be based on the ten-year average of Level III restoration costs. For every year that results in a negative balance, the actual Level III restoration costs that are applied to that negative balance[29] will be shared 90% by customers and 10% by PGE. In addition, if the balancing account exceeds a $12 million positive or negative balance, PGE will amortize the excess amount by either collection from (negative balance) or refund to (positive balance) customers

[29] If the Level III restoration costs exceed a positive reserve balance, only the costs that are applied to the negative balance will be subject to the sharing. The costs that take the balance to zero will not be subject to sharing. If the balance is already negative, all Level III restoration costs will be subject to the sharing percentages.

based on a 90/10 sharing of the excess amount. Our testimony and our Level III mechanism proposal addresses each of the Commission's concerns it raised in our last GRC. Specifically, we provide more justification for modifying the mechanism, a chain of causation justifying the change, and a sharing or allocation of risks.

Q. Does this conclude your testimony?

A. Yes

List of Exhibits

Exhibit	**Description**
801	Description of T&D Capital Projects
802	Seismic Evaluation Report
803	IOC Contractor Functions
804	IOC Critical Function Criteria
805	IOC Selection Criteria
806	Natural Resources IOC Site Evaluations
807	IOC Site Selection Scoring Activities
808	ADMS Functionalities and Conceptual View
809	ADMS Budgets by Size of Utility
810	Wildfire Mitigation Plan
811	Vegetation Management Trim Violations by Trim Cycles
812	Vegetation Management Crew Count
813	Vegetation Management Tree Related Outages
814	Milwaukie City Ordinance No. 2197
815	Portland Urban Forestry Programmatic Permit Portland General Electric
816	Level III Accrual

T&D Capital Project Descriptions

Integrated Operations Center (IOC) ($215.2 million)

- Discussed in Section IV of testimony.

Butler Substation Project ($70.6 million):

- The Butler Substation Project was implemented to serve new industrial load growth in the Hillsboro area. The project constructed a new 115kV substation in a breaker and one-half configuration. The project sectionalized two existing 115kV transmission lines to create the following four transmission lines to source the new substation: Butler-Sunset #1 115kV, Butler-Sunset #2 115kV, Butler-St Marys 115kV, and Butler-Orenco 115kV. The sectionalizing of these two lines provides more transmission system flexibility and increases reliability for all customers in the area supported by these substations. Two new 115kV capacitor banks will also be installed to provide voltage support on the transmission system. Two 150 MVA, 115/34.5kV distribution transformers, three 34.5kV distribution switchgear, and multiple new underground 34.5kV distribution feeders are also being constructed.
- The Butler Substation was energized in late 2020, with the 34.5kV distribution feeder work extending into early 2021. The Butler-St Marys 115kV and Butler-Sunset #2 115kV transmission lines will be reconductored in 2021 to provide additional capacity on the transmission system, with trailing costs into April 2022 for the Butler-Sunset #2 115kV reconductor.

Harborton Reliability Project Phase 1 ($55.3 million):

- Phase 1 of the Harborton Reliability Project rebuilt the 115kV yard, converting the station from a selective transfer station to a sectionalizing station in a breaker-and-one-half configuration, which provides increased reliability to customers supported by both the transmission and distribution systems in the area. A second distribution transformer was installed for redundancy on the distribution system, providing more capacity and flexibility during planned work and unplanned outages. In addition, a new 230kV breaker-and-one-half substation yard was constructed with two 230kV sources, created by sectionalizing the Rivergate-Trojan 230kV line to create the Harborton-Rivergate #1 230kV line and the Harborton-Trojan #1 230kV line. The Rivergate-Trojan 230kV line is part of the South of Allston Path; sectionalizing this line adds transmission system flexibility benefiting the entire region. Phase 1 of the Harborton Reliability Project was in service in Q2, 2021, with some trailing costs through the end of the year.

- The loss of the Rivergate VWR1 transformer can result in overloads and low voltage concerns in the North Portland area (both on PGE's system and PACW's system). A new 230/115kV, 320 MVA bulk power transformer was installed at Harborton to mitigate loading and voltage concerns for the loss of the Rivergate VWR1 transformer, meeting NERC compliance requirements.

<u>Blue Lake Phase II Project ($36.9 million):</u>

- The Blue Lake Phase II Project installed a second 230/115kV, 320 MVA bulk power transformer at the Blue Lake Substation, as well as a second 115kV ring bus with two new 115kV lines; one to the Tabor Substation and one to the McGill Substation. This project mitigated overloads on the Blue Lake VWR2 bulk power transformer and the Blue Lake-Fairview 115kV line, meeting NERC Compliance requirements. The installation of the second bulk power transformer at the Blue Lake Substation enabled the decommissioning of the antiquated Linneman Substation.

- The project also installed a second 115/13kV, 28 MVA distribution transformer and one distribution switchgear to provide capacity and flexibility for customers served in this area during planned or unplanned outages. In the future, two new 13kV distribution feeders are planned to provide additional system flexibility and to serve expected load growth in the area.
- The Blue Lake Phase II Project was completed in Q4, 2020, with trailing costs into 2021.

<u>Marquam Substation Project ($35.4 million):</u>

- The Marquam Substation Project constructed a new 115kV breaker-and-one-half GIS substation with three 115kV lines, including a new Harrison-Marquam 115kV line that was embedded into the Tilikum Crossing bridge. The substation includes both networked distribution infrastructure and radial distribution infrastructure, with three 115/13kV, 50 MVA distribution transformers serving the downtown Portland networked distribution system and two 115/13kV, 50 MVA distribution transformers serving radial distribution load in the South Waterfront area.
- The project enabled the retirement of the Stephens Substation and underwater 13kV distribution feeder cables serving the downtown Portland networked distribution system, which were critical assets that were past their end of asset life. Serving the downtown Portland networked distribution system from the new Marquam Substation improves reliability for these customers. The new load growth in the South Waterfront area necessitated the radial distribution infrastructure at the Marquam Substation.
- The majority of the Marquam Substation Project was completed in 2018. However, costs were incurred in 2019 to complete the distribution work, specifically the radial

distribution infrastructure and the cutover from the Stephens substation to the Marquam substation.

Unjacketed Cable Replacement Program ($33.6 million):

- The Unjacketed Cable Replacement Program (UCRP) executes projects to replace unjacketed cable across all of PGE’s service territory. Accelerated cable failure and demonstrated neutral corrosion of unjacketed cable types (particularly direct buried cable) drive the need for proactive replacement at a large scale. The total population of unjacketed cable in PGE's territory exceeds 3,000 miles. Based on risk analysis performed by Strategic Asset Management, 1,000 miles is currently due for replacement, with 2,500 miles expected to be due in 15 years.
- This project includes replacing unjacketed tapline cable within targeted areas prioritized by Strategic Asset Management. The project will also address repair or replacement of associated equipment that is unsafe or in disrepair; however, the project does not include replacement of unjacketed mainline cable or unjacketed substation getaway cables.

Brookwood Substation Conversion Project ($23.6 million):

- The Brookwood Substation Conversion Project converts the Brookwood Substation to 115kV, sourced by two new 115kV transmission lines; one from the Shute Substation and one from the St Marys Substation. New 115kV breaker positions will be installed at both substations to accommodate the new lines. The project provides a transmission source from Beaverton to the Shute Substation, increasing reliability to the North Hillsboro area and meeting NERC compliance requirements. The project also offloads the heavily-loaded 57kV system in the Hillsboro area, ensuring that customer reliability is maintained during peak loading conditions.

- The 115kV substation yard will be a 6-position ring bus breaker station with two 115/13kV, 50 MVA transformers and two distribution switchgear, increasing capacity to serve load from the substation by replacing the single existing 28 MVA transformer.
- Two new 13kV distribution feeders will be constructed to improve reliability to the region by offloading existing heavily loaded distribution feeders and providing operational flexibility.
- The Brookwood 115kV substation construction and the Brookwood-Shute 115kV line will be energized and close to plant by April 2022. The Brookwood-St Marys 115kV line and the new 13kV distribution feeders will be energized in the summer of 2022.

Helvetia Substation Project ($22.5 million):

- The Helvetia Substation Project was implemented to serve industrial load growth in the North Hillsboro area. The project will construct a new 115kV breaker-and-one-half configuration substation with two 115kV transmission sources, two 115/34.5kV, 50 MVA distribution transformers, and four 34.5kV distribution switchgear. Eight new underground 34.5kV distribution feeders will also be constructed. The project is scheduled for completion in Q3, 2021.
- The existing Shute-West Union 115kV line will be sectionalized and looped into the new substation for the two 115kV sources, creating the Helvetia-Shute 115kV line and the Helvetia-West Union 115kV line.

Rock Creek Substation ($21.2 million):

- The Rock Creek Substation Project constructed a new 115kV breaker station with two 115kV lines, one distribution transformer, one distribution switchgear, and three new 13kV feeders. The Sunset-West Union 115kV line was looped into the new substation, creating the Rock Creek-Sunset 115kV and Rock Creek-West Union 115kV lines. The Rock Creek Substation Project was completed in Q2, 2020, with trailing costs into 2021 for retention pond work.
- The new substation was constructed to alleviate heavy loading on the Bethany Substation and serve new load growth in the North Bethany area.

Roseway Substation Project ($20.3 million):

- The Roseway Substation Project constructed a new 115kV 6-position ring bus breaker station, with two 115kV lines, two 115/13kV, 28 MVA distribution transformers, two distribution switchgear, and three new 13kV feeders. The project was completed in Q2, 2021.
- The Orenco-Reedville 115kV line was looped into the new substation to provide the two 115kV sources, creating the Orenco-Roseway 115kV and Reedville-Roseway 115kV lines.
- The new substation was constructed to serve new load growth in the area, particularly the new South Hillsboro Community ("SoHi"), as well as to improve system flexibility for planned work and unplanned outages.

Division Transit Project ($19.3 million):

- The Division Transit Project requires work on 360 poles on Division St. in Portland, from SE 12th to Main St. in Gresham. The work will require pole replacements, pole relocations, and other smaller improvements to ensure proper clearances are maintained to new and existing infrastructure.

- This project was developed due to a Trimet Project, which updates their bus lines along Division St. with new bus shelters with electronic readouts and lighting, ADA access improvements, and updated boarding areas. At the same time, PBOT is updating their intersections with new steel poles and cross arms for traffic signals, as well as extending a fiber optic line between each end of the project.

PCB Transformer Replacement Project ($17.8 million):

- The PCB Transformer Replacement Project is a multi-year project scheduled for completion in 2025. The purpose of the project is to meet or exceed anticipated changes to PCB regulations, and to proactively and economically reduce PGE's liability associated with the potential release of PCBs into the environment in a safe, timely, and cost-effective manner.
- At the start of the project, PGE had approximately 182,000 pole/pad-mount and vault distribution transformers in its service territory, 75,351 of which were manufactured prior to 1987. Transformers manufactured prior to 1987 may have oil that contains polychlorinated biphenyl (PCB), which has been identified as an environmental and possible health hazard. All applicable distribution transformers will be tested and those transformers with PCB levels above certain thresholds will be replaced.

Field Voice Communications System Project (FVCS) ($17.4 million):

- The FVCS Project replaces the legacy radio system utilized across the PGE core service territory, including the West Side Hydro generation facilities and the Pelton/Round Butte generation facility. The project includes installing radios in approximately 1,000 fleet vehicles. The implementation of the FVCS Project requires the integration of multiple systems which will be comprised of Zetron (dispatch), Eventide (logging recorder) and Tallysman (GPS).

- A reliable radio system is crucial for day-to-day operations for our field personnel and operations staff to communicate, ensuring switching on the system is performed safely and no unplanned outages to customers occur.

<u>McGill Substation Project ($16.9 million):</u>

- The McGill Substation Project expanded the existing 115kV substation bus to a breaker-and-one-half configuration. In addition, a third 115/13kV, 28 MVA distribution transformer, third distribution switchgear, and new 13kV distribution feeders were added to the substation to serve load growth in the area. The project was completed in 2019, with trailing costs into 2020.

<u>Field Area Network (FAN) Project ($16.2 million):</u>

- A Field Area Network (FAN) implements a wireless communications data network that connects field sensors and control devices throughout an electrical system to an Integrated Operating Center. The FAN Project includes designing, procuring, and installing base stations (estimated at 90 physical locations, with three sectors each for a total of 270 Tier 1 base stations). These base stations will aggregate field traffic and transport it to the Integrated Operations Center (IOC) over the Multiprotocol Label Switching (MPLS) network and use fiber optic cables, microwave, or another radio path to connect to the final destinations.
- The FAN will use 700 MHz transceivers deployed on PGE's poles, towers, and substation assets. These radios will utilize PGE-owned and licensed spectrum,

providing coverage certainty, deployment flexibility, application prioritization, increased security, and lowest possible latency.

Horizon VWR3 Project ($13.3 million):

- The Horizon VWR3 Project installed a third 230/115kV, 320 MVA bulk power transformer at the Horizon Substation to mitigate overloads on the existing bulk power transformers caused by load growth in the area, meeting NERC compliance requirements. To accommodate the new transformer position at the Sunset Substation, which is the 115kV terminal for the Horizon Substation, the Rock Creek-Sunset 115kV line was tied to the Shute-Sunset #2 115kV line, creating the Rock Creek-Shute-Sunset 115kV line. The project was completed in Q2, 2021, with trailing costs through the end of the year.

Silverton Capacity Addition Project ($10.9 million):

- The Silverton Capacity Addition Project rebuilt the Silverton Substation to a 57kV breaker station, replacing all antiquated infrastructure within the substation. Two 9 MVA distribution transformers were replaced with one 115/13kV, 28 MVA distribution transformer for additional capacity. A new control enclosure was installed with protection and control equipment, including a Supervisory Control and Data Acquisition (SCADA) telemetry system for remote monitoring capabilities.
- The Silverton Project was completed in 2019, with trailing costs into 2020.

Willbridge Substation Project ($10.6 million):

- The Willbridge Substation Project rebuilds the Willbridge Substation to address assets past their end of life, as well as to eliminate the non-standard 11kV distribution voltage. The project includes rebuilding the substation's 115kV high side, upgrading station telemetry to SCADA, and replacing the existing 115/11kV, 20 MVA transformer with a new standard 115/13kV, 28 MVA transformer and new distribution switchgear. The project is scheduled for completion in Q3, 2021, with trailing costs through the end of the year.

- The Willbridge Substation Project will add the capacity needed to facilitate a future rebuild of the E Substation and to provide reliable backup to the Harborton Linnton feeder, while also enabling potential Distribution Automation deployment in the area to further reduce risk.

Shute Capacity Addition Project ($10.0 million):

- The Shute Capacity Addition Project will add two 115kV breaker positions to the Shute Substation to accommodate two new 115/34.5kV, 150 MVA transformers and two distribution switchgear. This project will be completed in Q1, 2022.
- The capacity at the Shute Substation must be increased to maintain full N-1 redundancy for all customers, due to new load growth from both existing customers and new customers being served from Shute Substation.

kpff

3 World Trade Center

ASCE 41-13 Seismic Evaluation Report

September 8, 2017
Revised September 19, 2017
Revised February 28, 2018

KPFF Project No. 10021600338

STRUCTURAL REGISTERED PROFESSIONAL ENGINEER
10542
OREGON
JULY 13, 19..
M. BRADLY MOYES
EXPIRES: 12-31-18

Prepared by:
KPFF Consulting Engineers
111 SW Fifth Avenue, Suite 2500
Portland, Oregon 97204

Submitted to:
World Trade Center
121 SW Salmon Street, 1WTC Suite 360
Portland, Oregon 97204

3 WORLD TRADE CENTER

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EXECUTIVE SUMMARY

A seismic evaluation of 3 World Trade Center (3WTC) was performed using American Society of Civil Engineers (ASCE) Standard 41-13, *Seismic Evaluation and Retrofit of Existing Buildings.* Evaluation of the structural frame was performed based on the requirements for an essential facility (Risk Category IV). Nonstructural components were evaluated using an ASCE 41-13 Tier 1 Screening for a Position Retention Performance Level. These requirements are intended to achieve a higher level of building performance than a more typical focus on life safety. A Category IV building is intended to be safe to occupy after an earthquake. The purpose of this report is to provide a detailed explanation of the evaluation process and results as well as to include retrofit details that will enhance the seismic resilience of the building.

The lateral force-resisting system for the building includes the steel moment frames at all column lines, the floor and roof diaphragms, and the supporting foundations which are spread footings. The beams have fully welded connections to the columns which act as rigid connections to resist seismic and wind forces. Detailing for steel moment frame connections has changed considerably as a result of what was learned from the 1994 Northridge Earthquake. As a result, these older style moment connections are no longer allowed by current code in high seismic areas such as Western Oregon; however, ASCE 41-13 includes procedures for their evaluation and acceptability at a reduced capacity.

The Portland area is subject to three sources of earthquakes:

- Local crustal earthquakes from nearby faults with a maximum size estimated at moment magnitude 6.2 to 7.0.
- Deep intraplate earthquakes similar to the moment magnitude 6.8 Nisqually earthquake that occurred in 2001. This source is thought to be capable of generating an earthquake with a maximum moment magnitude of 7.5.
- An interface event between the Juan de Fuca Plate and North American Plate on the Cascadia Subduction Zone. This source is thought to be capable of generating an earthquake with a moment magnitude of between 8.5 and 9.0.

Seismic forces and detailing requirements have changed significantly since construction, so as is true for most buildings of its age, 3 WTC does not comply with current seismic requirements for the large earthquakes required by the evaluation procedure used. Our evaluation determined that many of the steel moment frame members and connections were deficient and would require strengthening to be compliant. Therefore, heavy damage that could be a threat to life safety is expected for a large earthquake such as a Cascadia Subduction Zone earthquake or a large local event. 3 WTC foundations are founded on gravel and therefore liquefaction below the building is not anticipated.

3 WTC is expected to sustain relatively minor damage for earthquakes up to a moment magnitude of 5.0 to 5.5 or so for a local event. Increased damage would be expected for local earthquakes

larger than this magnitude. Because of the many variables with earthquakes and building responses, it is not possible to predict at what magnitude life threatening damage will occur.

A preliminary seismic upgrade scheme with our recommended retrofit work has been included in the report to allow budget pricing of the upgrade work. Additionally, the nonstructural deficiencies noted are recommended to be retrofitted. Completion of the upgrade work will significantly enhance the seismic resilience of the building. The preliminary upgrade scheme developed was based on the requirements for a Risk Category IV building which is more stringent than that required for a Risk Category II building. As a result, retrofit to a Risk Category II building would require less work.

INTRODUCTION AND SCOPE

3 World Trade Center (3WTC) is located at 121 SW Salmon Street in Portland, Oregon. KPFF Consulting Engineers was contracted by the World Trade Center to perform a seismic evaluation of the structure. American Society of Civil Engineers (ASCE) Standard 41-13, *Seismic Evaluation and Retrofit of Existing Buildings* was used to complete the evaluation. A Tier 3 Systematic Evaluation of the structural frame was performed based on the requirements as an "essential facility" (Risk Category IV). Nonstructural components were evaluated for a Position Retention Performance Level.

The seismic evaluation included a review of the original structural drawings, and an assessment of observable structural conditions and nonstructural conditions. Our review and the findings presented herein are limited to those conditions and components for which sufficient information could be found within the original structural drawings and confirmed on-site by the visual observations of KPFF structural personnel.

Observations, analyses, conclusions, and recommendations contained within this report reflect our engineering judgment. Concealed problems with the construction of the building may exist that cannot be revealed through drawings and site observations alone. KPFF can in no way warrant or guarantee the condition of the existing construction of the building, or the future building performance.

BUILDING DESCRIPTION

3WTC (originally designated as the Service Building) includes 5 stories of office space with two below grade levels of parking that is part of the three building World Trade Center complex shown in Figure 1. Construction of the complex was completed in 1977. 3WTC has a total of approximately 200,000 square feet and is approximately 100 feet tall. The typical floor plan is L-shaped with a typical layout as shown in Figure 2. The exterior cladding consists of granite panels. A portion of the Skybridge is attached to 3WTC, which connects the three buildings.

The lateral force-resisting system for the building includes the steel moment frames at all column lines, the floor and roof diaphragms, and the supporting foundations which are spread footings. The floor and roof diaphragms act to distribute lateral forces to the steel moment frames which include the columns and beams. The beams have fully welded connections to the columns which act as rigid connections to resist seismic and wind forces. These types of connections are no longer allowed by current code in high seismic areas such as Western Oregon.

A site survey of 3WTC revealed that the existing documents for the building are generally accurate for the original construction. Alterations to the original structure appear to be minor.

Figure 1 – World Trade Center Site (Google)

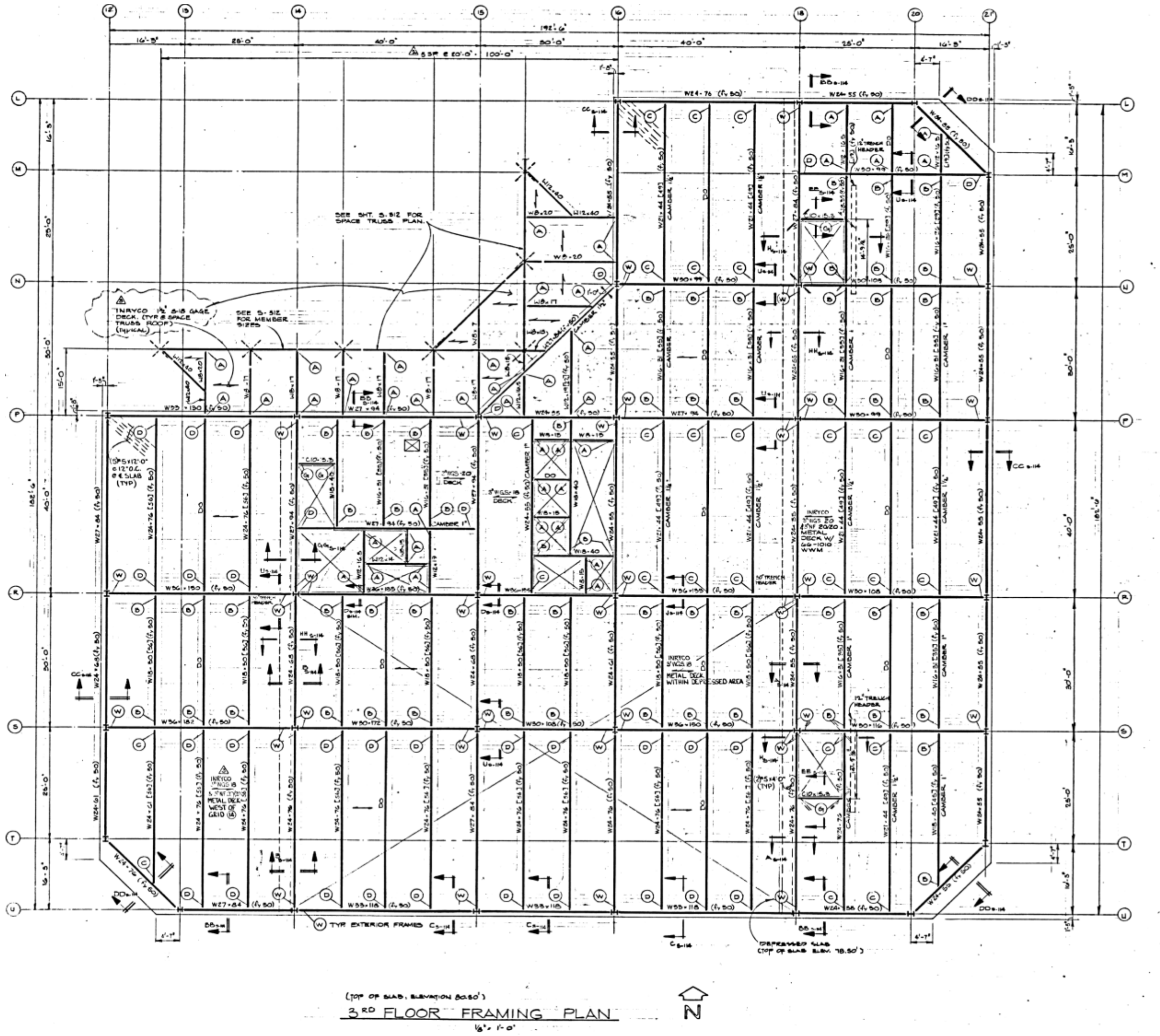

Figure 2 – Typical Floor Framing Plan

Document Review

The following documents were available for review:

Structural Drawings:
General Set – Sheets S-1 through S-5
Office Building – Sheets S-101 through S-115, dated January 6, 1975

The design criteria indicated on the structural drawings for the building are as follows:

- Building Code: 1973 Uniform Building Code (UBC)
- Wind: 25 psf Basic Zone

- Seismic: UBC Zone III
- Importance Factor: 1.0
- Live Loads: Office, 100 psf
  Roof, 25 psf
- Foundations: 8,000 psf Allowable Bearing Pressure
- Materials: Concrete Compressive Strength, 2500 psi (slabs on grade), 3000 psi (walls and wall footings), 4000 psi (beams, joists, elevated slabs, columns, column footings)
  Reinforcing Steel, ASTM 615, Grade 60 Structural Steel, ASTM A36 and ASTM A572 Grade 50 as noted
  Steel Bolts, ASTM A325

SITE OBSERVATIONS

KPFF conducted a site survey of the building on August 31, 2017 to determine the extent of seismic anchorage present for nonstructural elements, verify the general conformance of the existing documents and general building condition. The existing drawings appear to be generally accurate based on the visual observation of construction readily accessible to view. It appears that no significant structural modifications have been made to the building since the original construction.

The majority of the mechanical and electrical units were located in mechanical rooms on the P1 Level and on the 5^{th} floor. The original 5'x5' panel suspended ceilings were in place throughout most of the office spaces, with only a few remodeled areas containing newer ceilings. Partition walls in the office areas are typically light gauge framing with gypsum sheathing. Some CMU partition walls exist at the P1 Level and at stair enclosures.

SEISMIC EVALUATION

3WTC was evaluated using ASCE 41-13, *Seismic Evaluation and Retrofit of Existing Buildings* which utilizes a three-tiered process for evaluations. For this report, a Tier 3 Evaluation was performed for the structural frame as required for this building. A Tier 1 Screening was performed for the nonstructural elements. The three tiers are as follows:

Tier 1 – Screening: This procedure includes completing checklists for the structure and nonstructural items (reference Appendix A). During this phase, a review is performed utilizing available construction documents. In addition to the construction plans, a site visit is made to assess the condition for the existing structure for deterioration of the structure and finishes, and compare the existing structure to the information provided in available drawings. A Tier 1 screening was not performed for structural elements.

Tier 2 – Deficiency-Based Evaluation: The Tier 2 deficiency-based evaluation is an option which includes additional analysis and evaluation of all the potential deficiencies identified with a Tier 1 Screening. A Tier 2 evaluation was not performed for structural elements.

Tier 3 – Systematic Evaluation: The Tier 3 systematic procedure involves an analysis of the entire building and is required for a building exceeding a certain height for a particular building type. A Tier 3 evaluation was performed for this building.

The owner requested an evaluation of the structural frame based on the requirements for an "essential facility" (Risk Category IV). The performance objective, which includes both a seismic hazard level (size of earthquake) and performance objective, used for the evaluation was the Basic Performance Objective for Existing Buildings (BPOE).
The size of an earthquake is typically expressed in terms of moment magnitude which is a scale developed in the 1970s to succeed the 1930s-era Richter magnitude scale. Although the press often still refers to "Richter magnitude" for earthquakes (and the two scales produce similar results), the moment magnitude scale is used to express the size of modern earthquakes.

The Portland area is subject to three sources of earthquakes:

- Local crustal earthquakes from nearby faults with a maximum size estimated at moment magnitude 6.2 to 7.0.
- Deep intraplate earthquakes similar to the moment magnitude 6.8 Nisqually earthquake that occurred in 2001. This source is thought to be capable of generating an earthquake with a maximum moment magnitude of 7.5.
- An interface event between the Juan de Fuca Plate and North American Plate on the Cascadia Subduction Zone. This source is thought to be capable of generating an earthquake with a moment magnitude of between 8.5 and 9.0.

A Seismic Hazard Level is a measurement of how intense the ground shaking is predicted to be at the site during an earthquake. The BSE-1E and BSE-2E earthquakes used for our evaluation are a statistical combination of each of the three types of earthquakes that can occur in the Portland area taking into consideration the factors that contribute to the intensity of ground shaking at the site. These factors include the following:

- The types of potential faults that could affect the site.
- The distance of potential faults to the site.
- The local geological and geotechnical characteristics (how the earthquake waves travel through the ground).
- The likelihood (probability) of a seismic event on each fault.

The BPOE requires an analysis using two different hazard levels, the BSE-2E and the BSE-1E. BSE-2E is a larger less frequent earthquake that can occur once every 975 years. BSE-1E is a smaller more frequent earthquake that can occur once every 225 years. Both the BSE-2E and BSE-1E earthquakes include the Cascadia Subduction Zone earthquake by factoring in the probability of it happening within these recurrence intervals.

The following combinations of ground motions and performance levels were analyzed as required to satisfy the BPOE:

Risk Category	BSE-1E (20%/50 years)	BSE-2E (5%/50 years)
IV	Immediate Occupancy Structural Performance Position Retention Nonstructural Performance	Life Safety Structural Performance Nonstructural Performance Not Considered

The seismic analysis considers the following spectral response accelerations with Site Class C soils:

- BSE-1E (75% of BSE-1N minimum):
  - $S_{xs,\ BSE\text{-}1N\_75\%} = 0.496g$
  - $S_{x1,\ BSE\text{-}1N\_75\%} = 0.291g$

- BSE-2E:
  - $S_{xs} = 0.796g$
  - $S_{x1} = 0.458g$

The site is classified as having a High Level of Seismicity per ASCE 41-13.

A Life Safety Structural Performance Level assumes the following from a design earthquake event:

(a) Significant damage to the structure will occur but some margin against either partial or total structural collapse will remain.
(b) Some structural elements and components will be severely damaged, but this damage will not result in large falling debris hazards, either inside or outside the building.
(c) Injuries might occur during the earthquake; however, the overall risk of life-threatening injury as a result of structural damage is expected to be low.
(d) It should be possible to repair the structure; however, for economic reasons, this repair might not be practical.
(e) Although the damaged structure may not be an imminent collapse risk, it would be prudent to implement structural repairs or install temporary bracing before re-occupancy.

An Immediate Occupancy Structural Performance Level assumes the following from a design earthquake event:

(a) Only very limited damage to the structure will occur.
(b) The basic vertical and lateral force-resisting systems of the building retain almost all of their pre-earthquake strength and stiffness.
(c) The risk of life-threatening injury as a result of structural damage is very low.

(d) Although some minor structural repairs might be appropriate, these repairs would generally not be required before re-occupancy.
(e) Continued use of the building is not limited by damage or disruption to nonstructural elements of the building, furnishings, or equipment and availability of external utility services.

ASCE 41-13 FINDINGS

Structural Frame

The building's seismic performance was assessed in accordance with ASCE 41-13 using a three-dimensional linear dynamic analysis. The lateral force-resisting system includes steel moment frames at all column lines supported by spread footings. Evaluation of the steel moment frames include an analysis of the columns, beams, welded joints between the beams and columns, and the foundations.

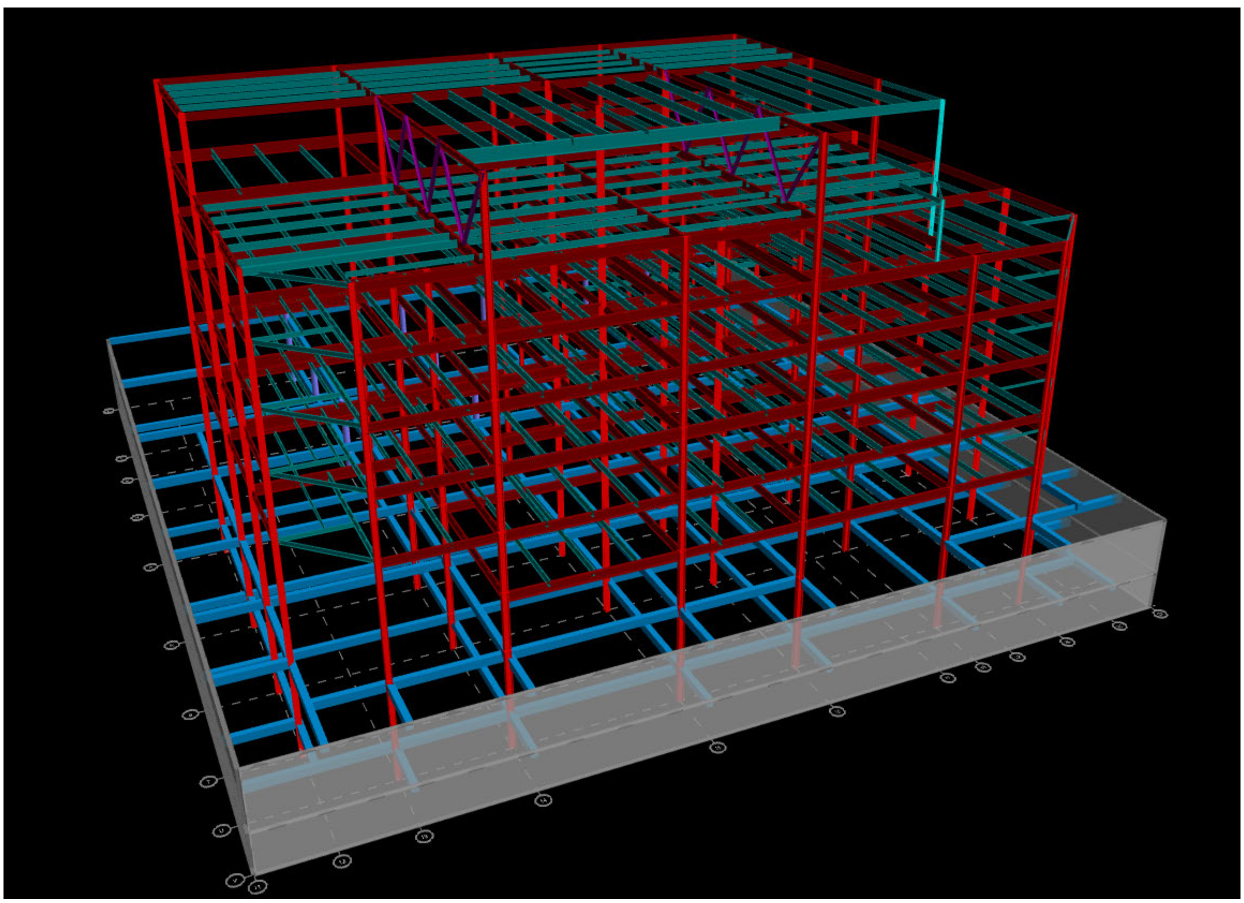

Figure 3 – 3WTC 3D Computer Analysis Model (RAM Frame)

The results of our assessment of the existing steel moment frames to resist seismic and gravity forces as a Risk Category IV building (essential facility) are as follows:

- Columns – Most of the columns are acceptable to resist seismic forces but some would be overstressed (about 10 column floor-sections out of 250 moment frame column floor-sections) and will require cover plate reinforcement. Some of the existing column splice joints would also be overstressed (about 25 splice joints out of 56 splice joints) and will require reinforcement at the existing splice joints. Below are the conceptual sketches of the cover plate reinforcement and column splice joint reinforcement:

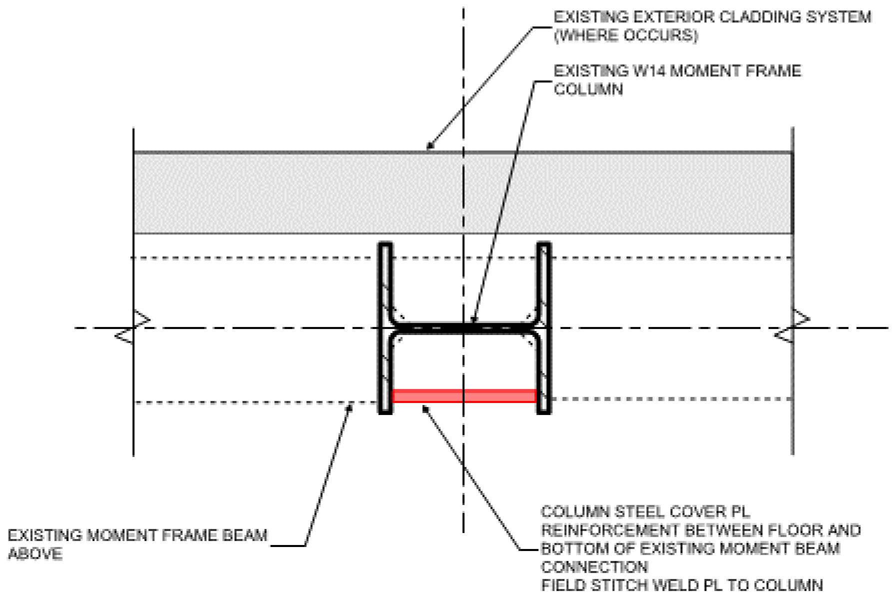

Figure 4 – Moment Frame Column Cover Plate Reinforcement

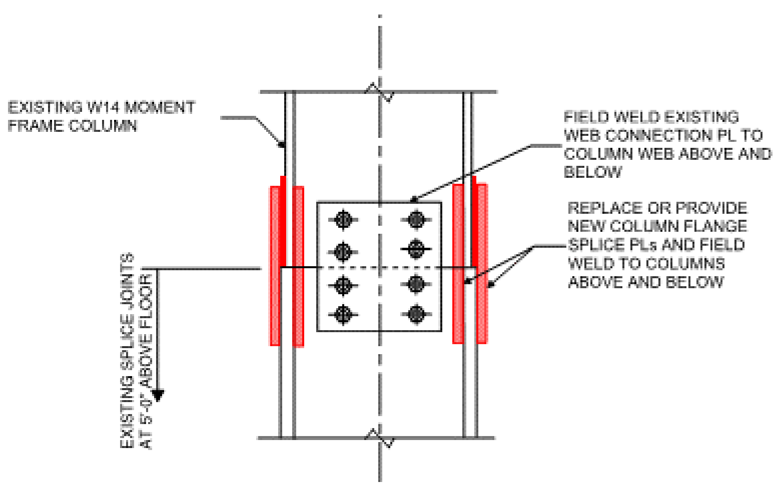

Figure 5 – Moment Frame Column Splice Joint Reinforcement

- Beams – Most of the moment frame beams require added bracing to brace the bottom flanges against rotation to resist seismic forces. Where typical floor framing is perpendicular to the moment frame beams, stiffeners can be added at the bottom of the existing beam to beam connections. A conceptual sketch of the stiffener reinforcement is shown in Figure 6. Where typical floor framing is parallel to the moment frame beams, angle kickers will be required, as shown in Figure 7.

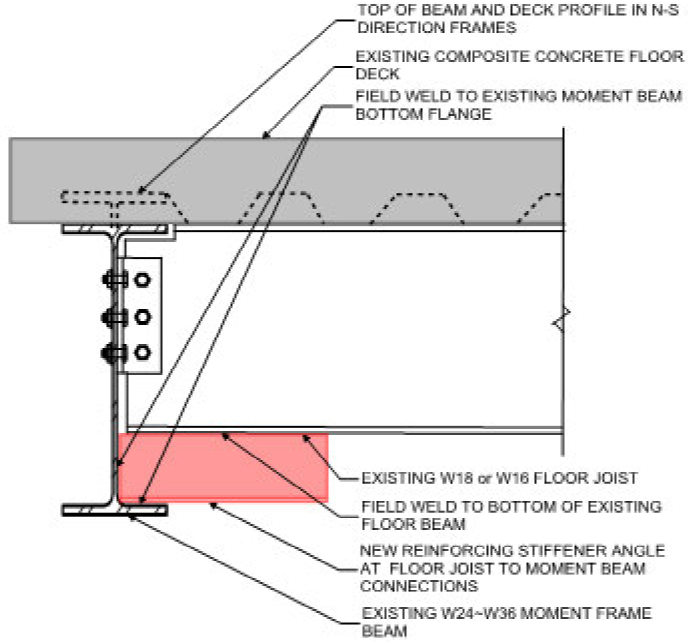

Figure 6 – Moment Frame Beam Bracing with Stiffeners

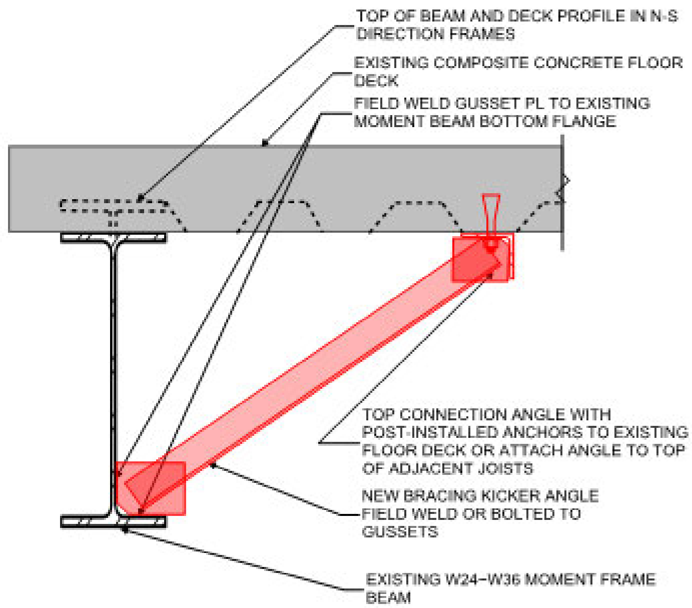

Figure 7 – Moment Frame Beam Bracing with Kicker Angle

- Beam-column Joints – Most of the beam-column joints are not acceptable and require retrofits to meet the requirements of ASCE 41-13. The weld overstresses range from 5% to 207%. Below are conceptual sketches of the connection reinforcement.

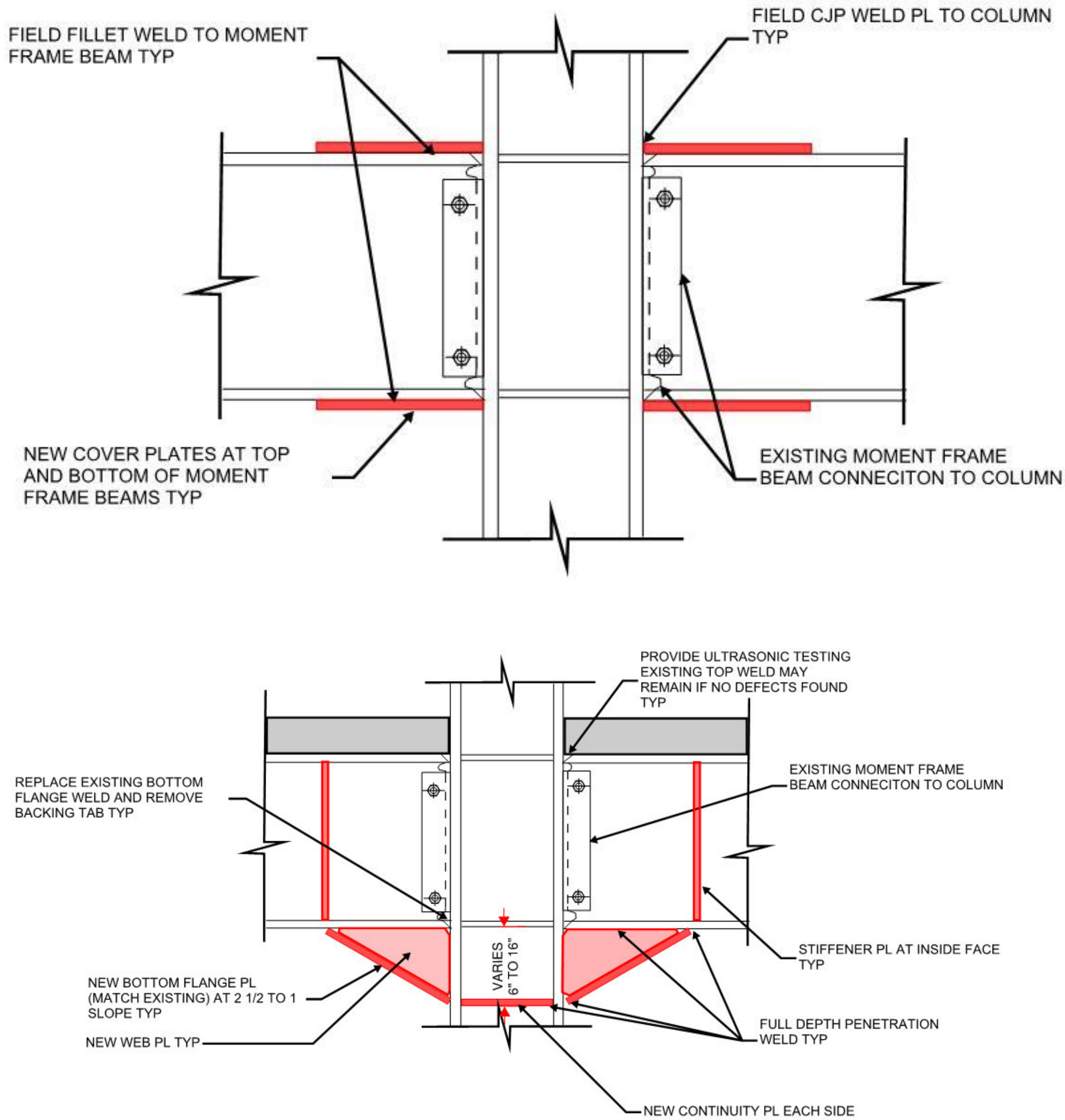

Figure 8 – Moment Frame Beam to Column Connection Reinforcement

- Foundations – All of the moment frame foundations are acceptable.

As noted in our summary above, many of the moment frame elements do not comply with the requirements for a Risk Category IV building. Seismic strengthening would be required to bring the building into compliance with the requirements of ASCE 41-13. The preliminary upgrade scheme developed was based on the requirements for a Risk Category IV building which is more stringent than that required for a Risk Category II building. As a result, retrofit to a Risk Category II building would require less work.

3 WTC is expected to sustain relatively minor damage for earthquakes up to a moment magnitude of 5.0 to 5.5 or so for a local event. Increased damage would be expected for local earthquakes larger than this magnitude. Because of the many variables with earthquakes and building responses, it is not possible to predict at what magnitude life threatening damage will occur.

GEOLOGIC SITE HAZARDS

The building's Geologic and Site Hazards were evaluated based on input provided by GRI. They have indicated that the risk of liquefaction or lateral spreading is low. They have classified the soils at the site as Site Class C. The complete report produced by GRI is included with the 1WTC evaluation.

NONSTRUCTURAL COMPONENTS

The building's nonstructural components were evaluated for Life Safety and Position Retention Performance Levels based on the requirements of ASCE 41-13. The corresponding Tier 1 checklists are provided in Appendix A of this report. Below is a summary of the items that were found to be nonconforming and will require mitigation.

Position Retention Nonstructural Performance Level (Risk Category IV building)

1. Fire Suppression Piping – Fire suppression piping was observed to have lateral bracing in some areas but not in others. In addition, the piping does not seem to have flexible couplings. It is recommended that a mechanical engineer review the system for compliance with NFPA-13.

2. Sprinkler Ceiling Clearance – Penetrations through ceilings appeared to have inadequate clearance with the exception of newer ceilings on the 5th floor.

3. Emergency Lighting – Emergency Lighting did not appear to be braced.

4. Hazardous Material Storage – Flammable materials in the P1 Mechanical room were in a fireproof cabinet, but the cabinet was not braced to structure.

Unbraced Flammable Materials Cabinet at P1 Level

5. Flexible Couplings – No flexible couplings were observed for natural gas piping.

6. Heavy Partitions Supported by Ceilings – CMU walls at P1 do not appear to have top bracing for out-of-plane movement.

7. Heavy Partitions Story Drifts – The CMU walls at P1 do not appear to have proper top bracing connection for in-plane and out-of-plane drifts. The CMU walls are also built tight against building columns without joints for building drift.

Unbraced CMU Partition Wall at Level P1

8. Light Partition Bracing – Light framed partition walls in original office spaces do not appear to have adequate bracing. Partition walls in the remodeled area on the 5th floor appear to be braced adequately.

9. Ceilings – The original 5’x5’ ceiling panel system does not appear to meet bracing, edge clearance, edge support, and seismic joint requirements.

10. Light Fixtures – Light fixtures at the original ceiling areas do not have an independent suspension system. In addition, the lens covers on light fixtures are not attached with safety devices.

11. Cladding and Glazing System – The existing granite panels are supported on steel tube frames attached to the floors. Although the details of the frames and their attachments are not available for review or analysis, we anticipate that they would be adequate to resist seismic forces. However, the adequacy of the glazing between panels is of concern. The glazing will need to be adequate to sustain floor drift (horizontal movement between floors). The details of the glass to panel connections are unknown. We recommend that

Benson Glass review the details of the glass connections at the top of the windows to assist with a determination of how much drift can be accommodated without window damage.

12. Stair Connection Details for Building Drift – The existing stair stringers are connected to floor slab edge channel with a vertical fillet weld at the joint of the C10 channel stringer web to the slab edge channel. No connection plate is used. The existing connection is nonductile and inadequate to accommodate building drifts. It is recommended that a welded angle clip be added to the connections as shown in Figure 9.

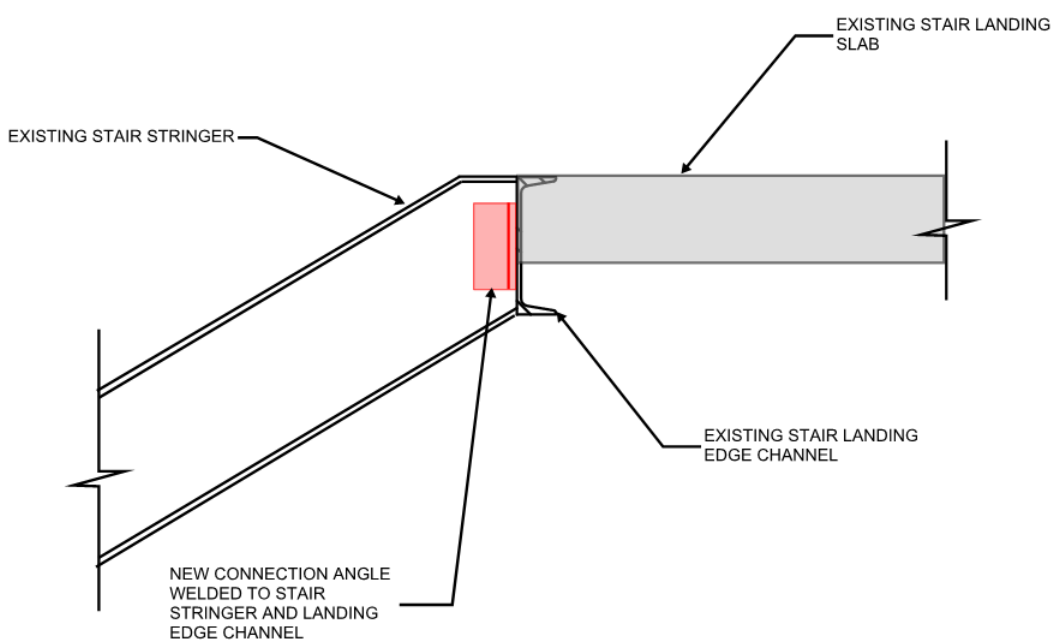

Figure 9 – Stair Stringer Connection to Support Channel

13. Tall Shelving and Fall Prone Contents – Storage racks, filing cabinets, lockers, and large appliances in kitchen areas were generally found to be unbraced.

Unbraced Lockers at Level 5

14. Mechanical and Electrical Equipment – In general, mechanical and electrical equipment was found to be braced. Exceptions included the two water heaters in the P1 Mechanical room. In addition, the vibration isolators under some equipment appeared to not have snubbers, and conduit larger than 2.5 inches did not appear to have flexible couplers.

Unbraced Water Heaters at P1 Level

Vibration Isolators Lacking Snubbers

15. Piping and Duct Runs – In general, piping and ducts were found to lack adequate bracing and flexible couplers. The newer piping and duct runs appeared to be braced.

Unbraced Piping Run at P1 Level

16. Elevators – Elevator retainer guards were observed at the sheaves and drums. Other requirements for the Position Retention performance level should be reviewed by the elevator manufacturer for compliance.

17. Cladding – The building cladding and glazing system is mostly hidden behind interior finishes so the connections were not visible, and no shop drawings were available for review. The system will need to be reviewed when future construction allows access for viewing.

Seismic Strengthening Triggers

Alterations to existing buildings are controlled by Chapter 34 of the 2014 Oregon Structural Specialty Code (OSSC) and Chapter 24.85 of the City Code titled *Seismic Design Requirements for Existing Buildings.* Seismic strengthening can be triggered by significant structural alterations, an addition, or a change in the occupancy type.

Changes in seismic forces resulting from alterations and additions are limited to a 10% increase in the force on any structural member unless the member complies, or is strengthened to comply, with current code per OSSC section 3403.4. Furthermore, per OSSC section 3403.4 it is not allowed to decrease the strength of any structural element resisting seismic forces by more than 10% unless it complies, or is strengthened to comply, with current code.

A change in occupancy to a more hazardous use can trigger a seismic upgrade of the entire building per OSSC section 3408 and Section 24.85.040 of the City Code. A change in occupancy to a lesser or equally hazardous use may be permitted by the building official without upgrading.

For remodel of 3WTC it is likely that no seismic strengthening would be required unless there are structural modifications made. Therefore, any seismic strengthening would likely be voluntary.

Phasing of Seismic Improvements

The seismic improvements required for the building can be phased as required to match with remodeling projects or open floors. The types of strengthening required does not change the strength or stiffness of the building significantly so the order in which it is accomplished is not critical.

Federally Leased Spaces

A Federally leased space is required to conform to the requirements of *Standards of Seismic Safety for Existing Federally Owned and Leased Buildings, ICSSC Recommended Practice 8 (RP 8)*. Most facilities are required to comply with the Basic Performance Objective for Existing Buildings (BPOE) unless considered a Mission Critical facility. If the building was strengthened to comply with ASCE 41-13 requirements for a Risk Category IV building, it would comply with the requirements for Mission Critical facilities. If the building was strengthened to comply with ASCE 41-13 requirements for a Risk Category II building (which is a less stringent criteria than the building was evaluated for), it would comply with the requirements for non-Mission Critical facilities.

GENERAL SUMMARY AND RECOMMENDATIONS

3WTC was evaluated using ASCE 41-13 criteria for compliance with the seismic requirements as an "essential facility" (Risk Category IV). The performance objective used for the evaluation was the Basic Performance Objective for Existing Buildings (BPOE). Based on the evaluation results, 3WTC presently has deficiencies for the criteria for Risk Category IV that could result in localized hazards, or partial or total collapse of the structure in a major seismic event. Additionally, there were many deficiencies of nonstructural elements that would require retrofit.

Seismic strengthening of the structural frame to meet Risk Category IV criteria would require beam bottom stiffeners or angle bracing to be added at all moment frame beams as well as strengthening of some columns, most column splices, and beam-column joints at most beam to column connections. Compliance with Risk Category IV criteria would also require mitigation of the nonstructural deficiencies noted. Design and detailing of the retrofit work is beyond the scope of this evaluation. The overall scope of seismic strengthening required to meet Risk Category IV criteria is quite extensive and may not be practical. Retrofit to a risk Category II criteria, which is less stringent, would require less work and may be practical

APPENDIX A

ASCE 41-13 CHECKLISTS

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	3WTC
SEISMICITY LEVEL:	
PROJECT NUMBER:	10021600338
COMPLETED BY:	Andi Camp
DATE COMPLETED:	8/31/2017
REVIEWED BY:	
REVIEW DATE:	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

16.17 Nonstructural Checklist

The Performance Level is designated LS for Life Safety or PR for Position Retention. The level of seismicity is designated as “not required” or by L, M, or H, for Low, Moderate, and High.

All Seismicity Levels

Life Safety Systems

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☒	N/A ☐	U ☐	LS-LMH; PR-LMH. FIRE SUPPRESSION PIPING: Fire suppression piping is anchored and braced in accordance with NFPA-13. (Commentary: Sec. A.7.13.1. Tier 2: Sec. 13.7.4)	
C ☐	NC ☐	N/A ☐	U ☒	LS-LMH; PR-LMH. FLEXIBLE COUPLINGS: Fire suppression piping has flexible couplings in accordance with NFPA-13. (Commentary: Sec. A.7.13.2. Tier 2: Sec. 13.7.4)	
C ☒	NC ☐	N/A ☐	U ☐	LS-LMH; PR-LMH. EMERGENCY POWER: Equipment used to power or control life safety systems is anchored or braced. (Commentary: Sec. A.7.12.1. Tier 2: Sec. 13.7.7)	
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. STAIR AND SMOKE DUCTS: Stair pressurization and smoke control ducts are braced and have flexible connections at seismic joints. (Commentary: Sec. A.7.14.1. Tier 2: Sec. 13.7.6)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

C	NC	N/A	U		
☐	☒	☐	☐	LS-MH; PR-MH. SPRINKLER CEILING CLEARANCE: Penetrations through panelized ceilings for fire suppression devices provide clearances in accordance with NFPA-13. (Commentary: Sec. A.7.13.3. Tier 2: Sec. 13.7.4)	
☐	☒	☐	☐	LS-not required; PR-LMH. EMERGENCY LIGHTING: Emergency and egress lighting equipment is anchored or braced. (Commentary: Sec. A.7.3.1. Tier 2: Sec. 13.7.9)	

Hazardous Materials

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. HAZARDOUS MATERIAL EQUIPMENT: Equipment mounted on vibration isolators and containing hazardous material is equipped with restraints or snubbers. (Commentary: Sec. A.7.12.2. Tier 2: 13.7.1)	
C	NC	N/A	U		
☐	☒	☐	☐	LS-LMH; PR-LMH. HAZARDOUS MATERIAL STORAGE: Breakable containers that hold hazardous material, including gas cylinders, are restrained by latched doors, shelf lips, wires, or other methods. (Commentary: Sec. A.7.15.1. Tier 2: Sec. 13.8.4)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name 8W-IC
Project Number 10021600338

C	NC	N/A	U	Statement	Comments
☒	☐	☐	☐	LS-MH; PR-MH. HAZARDOUS MATERIAL DISTRIBUTION: Piping or ductwork conveying hazardous materials is braced or otherwise protected from damage that would allow hazardous material release. (Commentary: Sec. A.7.13.4. Tier 2: Sec. 13.7.3 and 13.7.5)	
☒	☐	☐	☐	LS-MH; PR-MH. SHUT-OFF VALVES: Piping containing hazardous material, including natural gas, has shut-off valves or other devices to limit spills or leaks. (Commentary: Sec. A.7.13.3. Tier 2: Sec. 13.7.3 and 13.7.5)	
☐	☒	☐	☐	LS-LMH; PR-LMH. FLEXIBLE COUPLINGS: Hazardous material ductwork and piping, including natural gas piping, has flexible couplings. (Commentary: Sec. A.7.15.4, Tier 2: Sec.13.7.3 and 13.7.5)	
☐	☐	☐	☒	LS-MH; PR-MH. PIPING OR DUCTS CROSSING SEISMIC JOINTS: Piping or ductwork carrying hazardous material that either crosses seismic joints or isolation planes or is connected to independent structures has couplings or other details to accommodate the relative seismic displacements. (Commentary: Sec. A.7.13.6. Tier 2: Sec.13.7.3, 13.7.5, and 13.7.6)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name 8W-TC
Project Number 10021600338

Partitions

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. UNREINFORCED MASONRY: Unreinforced masonry or hollow-clay tile partitions are braced at a spacing of at most 10 ft in Low or Moderate Seismicity, or at most 6 ft in High Seismicity. (Commentary: Sec. A.7.1.1. Tier 2: Sec. 13.6.2)	
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. HEAVY PARTITIONS SUPPORTED BY CEILINGS: The tops of masonry or hollow-clay tile partitions are not laterally supported by an integrated ceiling system. (Commentary: Sec. A.7.2.1. Tier 2: Sec. 13.6.2)	
C ☐	NC ☒	N/A ☐	U ☐	LS-MH; PR-MH. DRIFT: Rigid cementitious partitions are detailed to accommodate the following drift ratios: in steel moment frame, concrete moment frame, and wood frame buildings, 0.02; in other buildings, 0.005. (Commentary A.7.1.2 Tier 2: Sec. 13.6.2)	
C ☐	NC ☒	N/A ☐	U ☐	LS-not required; PR-MH. LIGHT PARTITIONS SUPPORTED BY CEILINGS: The tops of gypsum board partitions are not laterally supported by an integrated ceiling system. (Commentary: Sec. A.7.2.1. Tier 2: Sec. 13.6.2)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name
Project Number 10021600338

C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	LS-not required; PR-MH. STRUCTURAL SEPARATIONS: Partitions that cross structural separations have seismic or control joints. (Commentary: Sec. A.7.1.3. Tier 2. Sec. 13.6.2)	
☐	☒	☐	☐	LS-not required; PR-MH. TOPS: The tops of ceiling-high framed or panelized partitions have lateral bracing to the structure at a spacing equal to or less than 6 ft. (Commentary: Sec. A.7.1.4. Tier 2. Sec. 13.6.2)	

Ceilings

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-MH; PR-LMH. SUSPENDED LATH AND PLASTER: Suspended lath and plaster ceilings have attachments that resist seismic forces for every 12 ft^2 of area. (Commentary: Sec. A.7.2.3. Tier 2: Sec. 13.6.4)	
☐	☐	☐	☒	LS-MH; PR-LMH. SUSPENDED GYPSUM BOARD: Suspended gypsum board ceilings have attachments that resist seismic forces for every 12 ft^2 of area. (Commentary: Sec. A.7.2.3. Tier 2: Sec. 13.6.4)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name 3WTC
Project Number 10021600338

C	NC	N/A	U		
C ☐	NC ☒	N/A ☐	U ☐	LS-not required; PR-MH. INTEGRATED CEILINGS: Integrated suspended ceilings with continuous areas greater than 144 ft^2, and ceilings of smaller areas that are not surrounded by restraining partitions, are laterally restrained at a spacing no greater than 12 ft with members attached to the structure above. Each restraint location has a minimum of four diagonal wires and compression struts, or diagonal members capable of resisting compression. (Commentary: Sec. A.7.2.2. Tier 2: Sec. 13.6.4)	
C ☐	NC ☒	N/A ☐	U ☐	LS-not required; PR-MH. EDGE CLEARANCE: The free edges of integrated suspended ceilings with continuous areas greater than 144 ft^2 have clearances from the enclosing wall or partition of at least the following: in Moderate Seismicity, 1/2 in.; in High Seismicity, 3/4 in. (Commentary: Sec. A.7.2.4. Tier 2: Sec. 13.6.4)	
C ☒	NC ☐	N/A ☐	U ☐	LS-not required; PR-MH. CONTINUITY ACROSS STRUCTURE JOINTS: The ceiling system does not cross any seismic joint and is not attached to multiple independent structures. (Commentary: Sec. A.7.2.5. Tier 2: Sec. 13.6.4)	
C ☐	NC ☒	N/A ☐	U ☐	LS-not required; PR-H. EDGE SUPPORT: The free edges of integrated suspended ceilings with continuous areas greater than 144 ft^2 are supported by closure angles or channels not less than 2 in. wide. (Commentary: Sec. A.7.2.6. Tier 2: Sec. 13.6.4)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

C	NC	N/A	U	Description	Comments
☐	☒	☐	☐	LS-not required; PR-H. SEISMIC JOINTS: Acoustical tile or lay-in panel ceilings have seismic separation joints such that each continuous portion of the ceiling is no more than 2500 ft^2 and has a ratio of long-to-short dimension no more than 4-to-1. (Commentary: Sec. A.7.2.7. Tier 2: 13.6.4)	

Light Fixtures

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☒	☐	☐	LS-MH; PR-MH. INDEPENDENT SUPPORT: Light fixtures that weigh more per square foot than the ceiling they penetrate are supported independent of the grid ceiling suspension system by a minimum of two wires at diagonally opposite corners of each fixture. (Commentary: Sec. A.7.3.2. Tier 2: Sec. 13.6.4 and 13.7.9)	
☐	☐	☒	☐	LS-not required; PR-H. PENDANT SUPPORTS: Light fixtures on pendant supports are attached at a spacing equal to or less than 6 ft and, if rigidly supported, are free to move with the structure to which they are attached without damaging adjoining components. (Commentary: A.7.3.3. Tier 2: Sec. 13.7.9)	
☐	☒	☐	☐	LS-not required; PR-H. LENS COVERS: Lens covers on light fixtures are attached with safety devices. (Commentary: Sec. A.7.3.4. Tier 2: Sec. 13.7.9)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name
Project Number 10021600338

Cladding and Glazing

RATING: C	NC	N/A	U	DESCRIPTION	COMMENTS
☐	☐	☐	☒	LS-MH; PR-MH. CLADDING ANCHORS: Cladding components weighing more than 10 lb/ft^2 are mechanically anchored to the structure at a spacing equal to or less than the following: for Life Safety in Moderate Seismicity, 6 ft; for Life Safety in High Seismicity and for Position Retention in any seismicity, 4 ft. (Commentary: Sec. A.7.4.1. Tier 2: Sec. 13.6.1)	
☐	☐	☐	☒	LS-MH; PR-MH. CLADDING ISOLATION: For steel or concrete moment frame buildings, panel connections are detailed to accommodate a story drift ratio of at least the following: for Life Safety in Moderate Seismicity, 0.01; for Life Safety in High Seismicity and for Position Retention in any seismicity, 0.02. (Commentary: Sec. A.7.4.3. Tier 2: Section 13.6.1)	
☐	☐	☒	☐	LS-MH; PR-MH. MULTI-STORY PANELS: For multi-story panels attached at more than one floor level, panel connections are detailed to accommodate a story drift ratio of at least the following: for Life Safety in Moderate Seismicity, 0.01; for Life Safety in High Seismicity and for Position Retention in any seismicity, 0.02. (Commentary: Sec. A.7.4.4. Tier 2: Sec. 13.6.1)	
☐	☐	☐	☒	LS-MH; PR-MH. PANEL CONNECTIONS: Cladding panels are anchored out-of-plane with a minimum number of connections for each wall panel, as follows: for Life Safety in Moderate Seismicity, 2 connections; for Life Safety in High Seismicity and for Position Retention in any seismicity, 4 connections. (Commentary: Sec. A.7.4.5. Tier 2: Sec. 13.6.1.4)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

C	NC	N/A	U		
☐	☐	☐	☒	LS-MH; PR-MH. BEARING CONNECTIONS: Where bearing connections are used, there is a minimum of two bearing connections for each cladding panel. (Commentary: Sec. A.7.4.6. Tier 2: Sec. 13.6.1.4)	
☐	☐	☒	☐	LS-MH; PR-MH. INSERTS: Where concrete cladding components use inserts, the inserts have positive anchorage or are anchored to reinforcing steel. (Commentary: Sec. A.7.4.7. Tier 2: Sec. 13.6.1.4)	
☐	☐	☐	☒	LS-MH; PR-MH. OVERHEAD GLAZING: Glazing panes of any size in curtain walls and individual interior or exterior panes over 16 ft^2 in area are laminated annealed or laminated heat-strengthened glass and are detailed to remain in the frame when cracked. (Commentary: Sec. A.7.4.8: Tier 2: Sec. 13.6.1.5)	

Masonry Veneer

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. TIES: Masonry veneer is connected to the backup with corrosion-resistant ties. There is a minimum of one tie for every 2-2/3 ft^2, and the ties have spacing no greater than the following: for Life Safety in Low or Moderate Seismicity, 36 in.; for Life Safety in High Seismicity and for Position Retention in any seismicity, 24 in. (Commentary: Sec. A.7.5.1. Tier 2: Sec. 13.6.1.2)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. SHELF ANGLES: Masonry veneer is supported by shelf angles or other elements at each floor above the ground floor. (Commentary: Sec. A.7.5.2. Tier 2: Sec. 13.6.1.2)	
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. WEAKENED PLANES: Masonry veneer is anchored to the backup adjacent to weakened planes, such as at the locations of flashing. (Commentary: Sec. A.7.5.3. Tier 2: Sec. 13.6.1.2)	
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. UNREINFORCED MASONRY BACKUP: There is no unreinforced masonry backup. (Commentary: Sec. A.7.7.2. Tier 2: Section 13.6.1.1 and 13.6.1.2)	
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. STUD TRACKS: For veneer with metal stud backup, stud tracks are fastened to the structure at a spacing equal to or less than 24 in. on center. (Commentary: Sec. A.7.6.1. Tier 2: Section 13.6.1.1 and 13.6.1.2)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	LS-MH; PR-MH. ANCHORAGE: For veneer with concrete block or masonry backup, the backup is positively anchored to the structure at a horizontal spacing equal to or less than 4 ft along the floors and roof. (Commentary: Sec. A.7.7.1. Tier 2: Section 13.6.1.1 and 13.6.1.2)	
☐	☐	☒	☐	LS-not required; PR-MH. WEEP HOLES: In veneer anchored to stud walls, the veneer has functioning weep holes and base flashing. (Commentary: Sec. A.7.5.6. Tier 2: Section 13.6.1.2)	
☐	☐	☒	☐	LS-not required; PR-MH. OPENINGS: For veneer with metal stud backup, steel studs frame window and door openings. (Commentary: Sec. A.7.6.2. Tier 2: Sec. 13.6.1.1 and 13.6.1.2)	

Parapets, Cornices, Ornamentation, and Appendages

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. URM PARAPETS OR CORNICES: Laterally unsupported unreinforced masonry parapets or cornices have height-to-thickness ratios no greater than the following: for Life Safety in Low or Moderate Seismicity, 2.5; for Life Safety in High Seismicity and for Position Retention in any seismicity, 1.5. (Commentary: Sec. A.7.8.1. Tier 2: Sec. 13.6.5)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	LS-LMH; PR-LMH. CANOPIES: Canopies at building exits are anchored to the structure at a spacing no greater than the following: for Life Safety in Low or Moderate Seismicity, 10 ft; for Life Safety in High Seismicity and for Position Retention in any seismicity, 6 ft. (Commentary: Sec. A.7.8.2. Tier 2: Sec. 13.6.6)	
☐	☐	☒	☐	LS-MH; PR-LMH. CONCRETE PARAPETS: Concrete parapets with height-to-thickness ratios greater than 2.5 have vertical reinforcement. (Commentary: Sec. A.7.8.3. Tier 2: Sec. 13.6.5)	
☐	☐	☒	☐	LS-MH; PR-LMH. APPENDAGES: Cornices, parapets, signs, and other ornamentation or appendages that extend above the highest point of anchorage to the structure or cantilever from components are reinforced and anchored to the structural system at a spacing equal to or less than 6 ft. This checklist item does not apply to parapets or cornices covered by other checklist items. (Commentary: Sec. A.7.8.4. Tier 2: Sec. 13.6.6)	

Masonry Chimneys

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. URM CHIMNEYS: Unreinforced masonry chimneys extend above the roof surface no more than the following: for Life Safety in Low or Moderate Seismicity, 3 times the least dimension of the chimney; for Life Safety in High Seismicity and for Position Retention in any seismicity, 2 times the least dimension of the chimney. (Commentary: Sec. A.7.9.1. Tier 2: 13.6.7)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. ANCHORAGE: Masonry chimneys are anchored at each floor level, at the topmost ceiling level, and at the roof. (Commentary: Sec. A.7.9.2. Tier 2: 13.6.7)	

Stairs

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. STAIR ENCLOSURES: Hollow-clay tile or unreinforced masonry walls around stair enclosures are restrained out-of-plane and have height-to-thickness ratios not greater than the following: for Life Safety in Low or Moderate Seismicity, 15-to-1; for Life Safety in High Seismicity and for Position Retention in any seismicity, 12-to-1. (Commentary: Sec. A.7.10.1. Tier 2: Sec. 13.6.2 and 13.6.8)	
C ☒	NC ☐	N/A ☐	U ☐	LS-LMH; PR-LMH. STAIR DETAILS: In moment frame structures, the connection between the stairs and the structure does not rely on shallow anchors in concrete. Alternatively, the stair details are capable of accommodating the drift calculated using the Quick Check procedure of Section 4.5.3.1 without including any lateral stiffness contribution from the stairs. (Commentary: Sec. A.7.10.2. Tier 2: 13.6.8)	

Contents and Furnishings

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. INDUSTRIAL STORAGE RACKS: Industrial storage racks or pallet racks more than 12 ft high meet the requirements of ANSI/MH 16.1 as modified by ASCE 7 Chapter 15. (Commentary: Sec. A.7.11.1. Tier 2: Sec. 13.8.1)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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C	NC	N/A	U	Statement	
☐	☒	☐	☐	LS-H; PR-MH. TALL NARROW CONTENTS: Contents more than 6 ft high with a height-to-depth or height-to-width ratio greater than 3-to-1 are anchored to the structure or to each other. (Commentary: Sec. A.7.11.2. Tier 2: Sec. 13.8.2)	
☐	☒	☐	☐	LS-H; PR-H. FALL-PRONE CONTENTS: Equipment, stored items, or other contents weighing more than 20 lb whose center of mass is more than 4 ft above the adjacent floor level are braced or otherwise restrained. (Commentary: Sec. A.7.11.3. Tier 2: Sec. 13.8.2)	
☐	☐	☒	☐	LS-not required; PR-MH. ACCESS FLOORS: Access floors more than 9 in. high are braced. (Commentary: Sec. A.7.11.4. Tier 2: Sec. 13.8.3)	
☐	☐	☒	☐	LS-not required; PR-MH. EQUIPMENT ON ACCESS FLOORS: Equipment and other contents supported by access floor systems are anchored or braced to the structure independent of the access floor. (Commentary: Sec. A.7.11.5. Tier 2: Sec. 13.7.7 and 13.8.3)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	LS-not required; PR-H. SUSPENDED CONTENTS: Items suspended without lateral bracing are free to swing from or move with the structure from which they are suspended without damaging themselves or adjoining components. (Commentary. A.7.11.6. Tier 2: Sec. 13.8.2)	

Mechanical and Electrical Equipment

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	LS-H; PR-H. FALL-PRONE EQUIPMENT: Equipment weighing more than 20 lb whose center of mass is more than 4 ft above the adjacent floor level, and which is not in-line equipment, is braced. (Commentary: A.7.12.4. Tier 2: 13.7.1 and 13.7.7)	
☒	☐	☐	☐	LS-H; PR-H. IN-LINE EQUIPMENT: Equipment installed in-line with a duct or piping system, with an operating weight more than 75 lb, is supported and laterally braced independent of the duct or piping system. (Commentary: Sec. A.7.12.5. Tier 2: Sec. 13.7.1)	
☒	☐	☐	☐	LS-H; PR-MH. TALL NARROW EQUIPMENT: Equipment more than 6 ft high with a height-to-depth or height-to-width ratio greater than 3-to-1 is anchored to the floor slab or adjacent structural walls. (Commentary: Sec. A.7.12.6. Tier 2: Sec. 13.7.1 and 13.7.7)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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C	NC	N/A	U		
☐	☐	☐	☒	LS-not required; PR-MH. MECHANICAL DOORS: Mechanically operated doors are detailed to operate at a story drift ratio of 0.01. (Commentary: Sec. A.7.12.7. Tier 2: Sec. 13.6.9)	
☐	☐	☒	☐	LS-not required; PR-H. SUSPENDED EQUIPMENT: Equipment suspended without lateral bracing is free to swing from or move with the structure from which it is suspended without damaging itself or adjoining components. (Commentary: Sec. A.7.12.8. Tier 2: Sec. 13.7.1 and 13.7.7)	
☐	☒	☐	☐	LS-not required; PR-H. VIBRATION ISOLATORS: Equipment mounted on vibration isolators is equipped with horizontal restraints or snubbers and with vertical restraints to resist overturning. (Commentary: Sec. A.7.12.9. Tier 2: Sec. 13.7.1)	
☒	☐	☐	☐	LS-not required; PR-H. HEAVY EQUIPMENT: Floor-supported or platform-supported equipment weighing more than 400 lb is anchored to the structure. (Commentary: Sec. A.7.12.10. Tier 2: 13.7.1 and 13.7.7)	

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C	NC	N/A	U		
☒	☐	☐	☐	LS-not required; PR-H. ELECTRICAL EQUIPMENT: Electrical equipment is laterally braced to the structure. (Commentary: Sec. A.7.12.11. Tier 2: 13.7.7)	
☐	☒	☐	☐	LS-not required; PR-H. CONDUIT COUPLINGS: Conduit greater than 2.5 in. trade size that is attached to panels, cabinets, or other equipment and is subject to relative seismic displacement has flexible couplings or connections. (Commentary: Sec. A.7.12.12. Tier 2: 13.7.8)	

Piping

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☒	☐	☐	LS-not required; PR-H. FLEXIBLE COUPLINGS: Fluid and gas piping has flexible couplings. (Commentary: Sec. A.7.13.2. Tier 2: Sec. 13.7.3 and 13.7.5)	
☐	☒	☐	☐	LS-not required; PR-H. FLUID AND GAS PIPING: Fluid and gas piping is anchored and braced to the structure to limit spills or leaks. (Commentary: Sec. A.7.13.4. Tier 2: Sec. 13.7.3 and 13.7.5)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

C	NC	N/A	U	DESCRIPTION	COMMENTS
☐	☒	☐	☐	LS-not required; PR-H. C-CLAMPS: One-sided C-clamps that support piping larger than 2.5 in. in diameter are restrained. (Commentary: Sec. A.7.13.5. Tier 2: Sec. 13.7.3 and 13.7.5)	
☐	☒	☐	☐	LS-not required; PR-H. PIPING CROSSING SEISMIC JOINTS: Piping that crosses seismic joints or isolation planes or is connected to independent structures has couplings or other details to accommodate the relative seismic displacements. (Commentary: Sec. A7.13.6. Tier 2: Sec.13.7.3 and Sec. 13.7.5)	

Ducts

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☒	☐	☐	LS-not required; PR-H. DUCT BRACING: Rectangular ductwork larger than 6 ft^2 in cross-sectional area and round ducts larger than 28 in. in diameter are braced. The maximum spacing of transverse bracing does not exceed 30 ft. The maximum spacing of longitudinal bracing does not exceed 60 ft. (Commentary: Sec. A.7.14.2. Tier 2: Sec. 13.7.6)	
☒	☐	☐	☐	LS-not required; PR-H. DUCT SUPPORT: Ducts are not supported by piping or electrical conduit. (Commentary: Sec. A.7.14.3. Tier 2: Sec. 13.7.6)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	LS-not required; PR-H. DUCTS CROSSING SEISMIC JOINTS: Ducts that cross seismic joints or isolation planes or are connected to independent structures have couplings or other details to accommodate the relative seismic displacements. (Commentary: Sec. A.7.14.5. Tier 2: Sec. 13.7.6)	

Elevators

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	LS-H; PR-H. RETAINER GUARDS: Sheaves and drums have cable retainer guards. (Commentary: Sec. A.7.16.1. Tier 2: 13.8.6)	
☐	☐	☐	☒	LS-H; PR-H. RETAINER PLATE: A retainer plate is present at the top and bottom of both car and counterweight. (Commentary: Sec. A.7.16.2. Tier 2: 13.8.6)	
☐	☐	☐	☒	LS-not required; PR-H. ELEVATOR EQUIPMENT: Equipment, piping, and other components that are part of the elevator system are anchored. (Commentary: Sec. A.7.16.3. Tier 2: 13.8.6)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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C	NC	N/A	U		
☐	☐	☐	☒	LS-not required; PR-H. SEISMIC SWITCH: Elevators capable of operating at speeds of 150 ft/min or faster are equipped with seismic switches that meet the requirements of ASME A17.1 or have trigger levels set to 20% of the acceleration of gravity at the base of the structure and 50% of the acceleration of gravity in other locations. (Commentary: Sec. A.7.16.4. Tier 2: 13.8.6)	
C	NC	N/A	U		
☐	☐	☐	☒	LS-not required; PR-H. SHAFT WALLS: Elevator shaft walls are anchored and reinforced to prevent toppling into the shaft during strong shaking. (Commentary: Sec. A.7.16.5. Tier 2: 13.8.6)	
C	NC	N/A	U		
☐	☐	☐	☒	LS-not required; PR-H. COUNTERWEIGHT RAILS: All counterweight rails and divider beams are sized in accordance with ASME A17.1. (Commentary: Sec. A.7.16.6. Tier 2: 13.8.6)	
C	NC	N/A	U		
☐	☐	☐	☒	LS-not required; PR-H. BRACKETS: The brackets that tie the car rails and the counterweight rail to the structure are sized in accordance with ASME A17.1. (Commentary: Sec. A.7.16.7. Tier 2: 13.8.6)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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C ☐	NC ☐	N/A ☐	U ☒	LS-not required; PR-H. SPREADER BRACKET: Spreader brackets are not used to resist seismic forces. (Commentary: Sec. A.7.16.8. Tier 2: 13.8.6)	
C ☐	NC ☐	N/A ☐	U ☒	LS-not required; PR-H. GO-SLOW ELEVATORS: The building has a go-slow elevator system. (Commentary: Sec. A.7.16.9. Tier 2: 13.8.6)	

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APPENDIX B

SUMMARY DATA SHEET

BUILDING DATA

Building Name: 3 WTC
Date: 9/6/17
Building Address: 121 SW Salmon Street, Portland, Oregon
Latitude: 45.515772
Longitude: -122.674684
By: Andi Camp

Year Built: 1977
Year(s) Remodeled:
Original Design Code: 1973 UBC
Area (sf): 200,000
Length (ft): 193
Width (ft): 183
No. of Stories: 7
Story Height: 15 feet
Total Height: 100 feet

USE

☐ Industrial ☑ Office ☐ Warehouse ☐ Hospital ☐ Residential ☐ Educational ☐ Other: ______

CONSTRUCTION DATA

Gravity Load Structural System: Concrete slab on metal deck with steel framing
Exterior Transverse Walls: Granite and glazing — Openings? Yes
Exterior Longitudinal Walls: Granite and glazing — Openings? Yes
Roof Materials/Framing: Metal deck on steel framing
Intermediate Floors/Framing: Slab on metal deck on steel framing
Ground Floor: Concrete slab on joists
Columns: Steel — Foundation: Spread footings
General Condition of Structure: Good
Levels Below Grade? 2
Special Features and Comments: Skybridge connecting 3 buildings

LATERAL-FORCE-RESISTING SYSTEM

	Longitudinal	Transverse
System:	Steel moment frames	Steel moment frames
Vertical Elements:	Steel WF columns	Steel WF columns
Diaphragms:	Slab on metal deck	Slab on metal deck
Connections:	Welded flanges	Welded flanges

EVALUATION DATA

BSE-1N Spectral Response Accelerations: S_{Ds}= 0.726g — S_{D1}= 0.445g
Soil Factors: Class= C — F_a= 1.006 — F_v= 1.377
BSE-1E Spectral Response Accelerations: S_{XS}= 0.355g — S_{X1}= 0.189g
Level of Seismicity: High — Performance Level: Immediate occupancy
Building Period: T= 1.471 s
Spectral Acceleration: S_a= 0.198
Modification Factor: $C_mC_1C_2$= 0.9 — Building Weight: W= 12,949 kips
Pseudo Lateral Force: $V= C_mC_1C_2S_aW$= 0.178

BUILDING CLASSIFICATION: S1

REQUIRED TIER 1 CHECKLISTS

	Yes	No
Basic Configuration Checklist	☐	☑
Building Type ____ Structural Checklist	☐	☑
Nonstructural Component Checklist	☑	☐

FURTHER EVALUATION REQUIREMENT: ______

IOC Contractor Functions

- **Owner's Representative** represents and advises PGE on preliminary site engineering, assesses the viability of design, ensures adherence to the design scope, manages the project schedule and reporting (including status), provides on-site construction quality control, and mediates between the Architect/Engineer and the CM/GC. The contracted Owner's Representative has extensive experience in the Portland design and construction industry. Past projects include the Daimler Trucks North America headquarters building, Port of Portland headquarters, and Clackamas Community College expansion program.
- **Architect/Engineer** develops the space program, master plan, schematic designs, construction drawings, provides project cost estimates, supports permit procurement, monitors construction, and provides as-built documentation. The Architect/Engineer retained for the project has recent related experience in developing mission-critical facilities for the California Independent System Operator (CAISO), State of California, and Sacramento Municipal Utility District (SMUD).
- **Construction Manager/General Contractor (CM/GC)** provides advisory services to the Architect/Engineer, procures permits, contracts construction work, provides a guaranteed maximum price for the project, and manages the construction of the facility. The CM/GC retained for the project is based in the Pacific Northwest and has relevant experience. Specifically, it constructed operations centers for Eugene Water and Electric Board and Central Lincoln Public Utility District and is familiar with the specialized resiliency and security considerations these facilities require.

IOC Critical Function Criteria

Category	Function	Description
Mission Critical Operations	**Energy Supply**	The function operates 24 hours/day, 7 days/week, 365 days/year and it is responsible for provisioning energy supply to the grid, either through scheduling PGE generation or transacting with other counterparties to ensure power supply in real-time. The function is in the current SCC.
	Bulk Electric System	The function operates 24 hours/day, 7 days/week, 365 days/year and it is responsible for operating the bulk electric system by directing energy flow on the PGE transmission network. The function is in the current SCC.
	Distribution	The function operates 24 hours/day, 7 days/week, 365 days/year and it is responsible for operating the distribution electric system by directing energy flow between the bulk electric system and retail customers on the PGE distribution network. The function is proposed to be in the SCC (and the IOC?) as part of the ADMS implementation project.
	24/7 System Support	The function operates 24 hours/day, 7 days/week, 365 days/year and it is responsible for the maintenance and operation of the hardware and software systems required for the provision of energy supply to the grid, operating the bulk electric system, and operating the distribution electric system. The function is in the current SCC or is proposed to be in the SCC as part of the ADMS implementation project.
Resiliency	**Emergency Response & Recovery**	The function is responsible for the planning, coordination and execution of response and recovery plans to maintain energy supply and grid reliability (storm, fire, earthquake recovery, Incident Command Structure). The function must access the SCC or back-up SCC to fulfill its responsibilities.
	Critical Infrastructure Protection (CIP)	The function is responsible for managing assets protected by NERC CIP and that are required for mission-critical operations. The function must access the SCC to fulfill its responsibilities.
	Physical/Cyber Security	The function is responsible for protecting personnel, assets, hardware, software, networks, and data from physical and cyber threats that

Category	Function	Description
		could cause loss or damage. The function must access the SCC to fulfill its responsibilities.

IOC Support Function Criteria

Category	Criteria	Description
Support Functions	**Function Influences Mission Critical Operations**	The function processes inputs or outputs that directly support the provision of energy supply to the grid, operation of the bulk electric system, operation of the distribution electric system, or operation of the systems supporting those functions (supported by proximity of functions). This includes functions that provide proactive identification of issues and facilitate the associated responses.
	Mission Critical Operations Dependent Function	The operation of the function is guided by the process inputs or outputs from the provision of energy supply to the grid, operation of the bulk electric system or distribution electric system, or the operation of the systems supporting those functions.
	Business Hours System Support	The function manages the operation of the systems required to support the provision of energy supply to the grid, operating the bulk electric system, and operating the distribution electric system but that are not mission-critical. These include after-the-fact analytical tools.
Tools / Systems	**Software**	The function manages, supports or utilizes software operated for mission-critical operations, resiliency, or their support functions.
	Communications (Radio, Network)	The function manages, supports, or utilizes communications hardware for mission-critical operations, resiliency, or their support functions
	Data & Analytics	The function manages, supports, collects, or utilizes data derived from or used in mission-critical operations, resiliency, or their support functions.

IOC Site Selection Criteria

	CRITERIA	DESCRIPTION	SCORE METHODOLOGY	WEIGHT
Location/Land Quality				**40%**
1	Land Parcel Size	Land parcel size is large enough to accommodate building, appropriate parking, and security	25-30 acres = 5 30-35 acres = 4 20-25 acres = 3 35-40 acres = 2 40 acres or more = 1 Less than 20 acres = 1	8
2	Buildable Acreage*	Amount of land parcel that is qualified/appropriate for building (as provided by Broker)	Over 60% = 5 50% - 60% = 4 40% - 50% = 3 30% - 40% = 2 20% - 30% = 1 Less than 20% = 0	8
3	Within PGE Service Territory*	Land parcel is located within PGE service territory	Within PGE Service Territory = 1 Outside PGE Service Territory = 0	10
4	Appropriate Zoning*	Zoning is appropriate for use as operations center	Land parcel is currently zoned for use = 5 Land parcel zoning can be changed for use = 2 Land parcel zoning cannot be changed for use = 0	4
5a	Site Serviceability - Communications	The extent to which the site is serviced by necessary communications infrastructure (redundant fiber and communications tower)	Site has all necessary services = 5 Site requires services at a cost of less than $500,000 = 4 Site requires services at a cost of less than $1,000,000 = 3 Site requires services at a cost of less than $1,500,000 = 2 Site requires services at a cost over $1,500,000 = 1	5
5b	Site Serviceability – Distribution Network	The extent to which the site is serviced by necessary distribution network infrastructure (distribution feeder from 2 independent sources/acceptable feeder reliability	Site requires services at a cost of less than $1,000,000 = 5 Site requires services at a cost of less than $2,500,000 = 4 Site requires services at a cost of less than $5,000,000 = 3 Site requires services at a cost of less than $7,500,000 = 2 Site requires services at a cost over $10,000,000 = 1	5

	CRITERIA	DESCRIPTION	SCORE METHODOLOGY	WEIGHT
		metrics (SAM model))		
6	Site Cost	Price per square foot	\$8 or less = 5 \$9 or less = 4 \$10 or less = 3 \$11 or less = 2 \$12 or more = 1	7
7	PGE-Owned Site	Existing PGE ownership of land parcel	Currently owned = 5 Not currently owned = 0	6
8	Future Expansion	Ability to expand from 150,000 sq. ft. building(s)	Able to increase space by 41% to 50% = 5 Able to increase space by 51% or more = 4 Able to increase space by 31% to 40% = 3 Able to increase space by 21% to 30% = 2 Able to increase space by 10% to 20% = 1 Not able to increase space = 0	7
9	Impact Adjacent Uses	Potential negative impact on adjacent properties	Minimal impact on adjacent uses = 5 Moderate impact on adjacent uses = 3 Substantial impact on adjacent uses = 1	5
10	Site Preparation Costs	If site is brownfield and requires demolition and remediation, cost at \$ per square foot (\$9 for clean demo/hauling; \$15.50 for contaminated debris)	\$1,000,000 or less = -1 \$1,000,001-\$2,000,000 = -2 \$2,000,001-\$3,000,000 = -3 \$3,000,001-\$4,000,000 = -4 \$4,000,001 or more = -5	6
11	Area Crime Trends	Statistics as compiled by local jurisdictions (heat maps) trending over the last three years. All-inclusive for all crime types (violent and property).	Low crime rate = 5 Medium crime rate = 3 High crime rate = 1	6
12	Emergency Services Response Time	Time from call made to the arrival of emergency service. Local jurisdictions should	10 minutes or less = 5 10 – 15 minutes = 3 More than 15 minutes = 1	7

	CRITERIA	DESCRIPTION	SCORE METHODOLOGY	WEIGHT
		have specific details regarding response times.		
Transportation				**20%**
13	Ingress/Egress Accessibility	Ability of local road/traffic infrastructure to support medium- to large-scale employee ingress/egress from site	On the intersection of two arterial roads = 5 On an arterial road within 5 blocks of another arterial road = 4 On an arterial road more than 5 blocks from another arterial road = 3 On a collector road within 5 blocks of an arterial road = 2 On a collector road more than 5 blocks from an arterial road = 1	8
14	Road Links	Portland Bureau of Emergency Management has designated emergency transportation routes as priority for maintaining open for travel	Within 0.5 miles of Emergency Transportation Route = 5 Within 0.5-1.0 miles of Emergency Transportation Route = 4 Within 1.0-1.5 miles of Emergency Transportation Route = 3 Within 1.5-2.0 miles of Emergency Transportation Route = 2 Within 2.0-2.5 miles of Emergency Transportation Route = 1 Over 2.5 miles from Emergency Transportation Route = 0	8
15	Transit Links	Distance from public transit	Within 1 mile of existing or planned public transit = 5 Within 2 miles of existing or planned public transit = 4 Within 3 miles of existing or planned public transit = 3 Within 4 miles of existing or planned public transit = 2 More than 5 miles existing or planned public transit = 1	6
16	Congestion Factor - Beaverton	Average travel time between site and Beaverton	Less than 20 minutes = 5 Between 20 and 30 minutes = 4 Between 30 and 40 minutes = 3 Between 40 and 50 minutes = 2 Over 50 minutes = 1	6
17	Congestion Factor - Wilsonville	Average travel time between site and Wilsonville	Less than 20 minutes = 5 Between 20 and 30 minutes = 4 Between 30 and 40 minutes = 3	5

	CRITERIA	DESCRIPTION	SCORE METHODOLOGY	WEIGHT
			Between 40 and 50 minutes = 2 Over 50 minutes = 1	
18	Congestion Factor - Vancouver	Average travel time between site and Vancouver	Less than 20 minutes = 5 Between 20 and 30 minutes = 4 Between 30 and 40 minutes = 3 Between 40 and 50 minutes = 2 Over 50 minutes = 1	6
19	Congestion Factor - Gresham	Average travel time between site and Gresham	Less than 20 minutes = 5 Between 20 and 30 minutes = 4 Between 30 and 40 minutes = 3 Between 40 and 50 minutes = 2 Over 50 minutes = 1	6
20	Congestion Factor - Downtown	Average travel time between site and Downtown	Less than 20 minutes = 5 Between 20 and 30 minutes = 4 Between 30 and 40 minutes = 3 Between 40 and 50 minutes = 2 Over 50 minutes = 1	6
21	Congestion Factor - Hillsboro	Average travel time between site and Downtown	Less than 20 minutes = 5 Between 20 and 30 minutes = 4 Between 30 and 40 minutes = 3 Between 40 and 50 minutes = 2 Over 50 minutes = 1	6
Disaster Risk/Recovery				**40%**
22	Flood Risk Exposure	Distance from either the effective or preliminary FEMA 100 yr. Flood Hazard Area (as identified by Oregon Department of Geology and Mineral Industries in the current Statewide Geohazards Viewer)	More than 1 mile from flood area = 5 0.5 – 1 mile from flood area = 3 Less than 0.5 miles from flood area = 0	8

	CRITERIA	DESCRIPTION	SCORE METHODOLOGY	WEIGHT
23	Cascadia Earthquake Risk Exposure	Degree of shaking that can be expected in the case of a magnitude 9.0 Cascadia Subduction Zone earthquake (as identified by Oregon Department of Geology and Mineral Industries in the current Statewide Geohazards Viewer). Note: No areas in Portland metro have been identified as being in a "Light" shaking risk zone.	Moderate shaking = 5 Strong shaking = 3 Very Strong shaking = 1 Severe or Violent shaking = 0	9
24	Earthquake Shaking Hazard Risk Exposure	Degree of shaking that can be expected in the case of an earthquake in a 500-year period (as identified by Oregon Department of Geology and Mineral Industries in the current Statewide Geohazards Viewer). Note: No areas in Portland metro have been identified as being in a "Light" or "Moderate" shaking risk zone.	Strong shaking = 3 Very Strong shaking = 1 Severe or Violent shaking = 0	9
25	Fault Line Risk Exposure	Distance from faults identified by the US Geological Survey as having moved in the last 1.6 million years	More than 3 miles from active fault line = 5 2 – 3 miles from active fault line = 3 1 – 2 miles from active fault line = 1 Less than 1 mile from active fault line = 0	8

	CRITERIA	DESCRIPTION	SCORE METHODOLOGY	WEIGHT
		(as identified by Oregon Department of Geology and Mineral Industries in the current Statewide Geohazards Viewer).		
26	Liquefaction Risk Exposure	Likelihood of soil liquefaction occurring during the course of an earthquake (as identified by Oregon Department of Geology and Mineral Industries in the current Statewide Geohazards Viewer).	No likelihood of soil liquefaction = 5 Low likelihood of soil liquefaction = 3 Moderate likelihood of soil liquefaction = 1 High likelihood of soil liquefaction = 0	9
27	Landslide Risk Exposure	Susceptibility of land parcel to landslides (as identified by Oregon Department of Geology and Mineral Industries in the current Statewide Geohazards Viewer).	Low – Landsliding unlikely = 5 Moderate – Landsliding possible = 3 High/Very High – Landsliding likely/existing landslides = 0	8
28	Wildfire Risk Exposure	Susceptibility and proximity of land parcel to wildfires (as identified by "Fire Risk Assessment")	Low = 5 Moderate = 3 High = 0	5
29	Proximity to Bulk Electric Substation	Distance from priority substations for power restoration after disaster	Within 1 mile of Bulk Electric Substation = 5 Within 1-1.5 miles of Bulk Electric Substation = 4 Within 1.5-2.0 miles of Bulk Electric Substation = 3	8

	CRITERIA	DESCRIPTION	SCORE METHODOLOGY	WEIGHT
			Within 2.0-2.5 miles of Bulk Electric Substation = 2 Within 2.5-3.0 miles of Bulk Electric Substation = 1 Over 3 miles from Bulk Electric Substation = 0	
30	Proximity to Freight Rail Line	Distance from rail line to mitigate risk of exposure to derailed or otherwise impaired rail cars	More than 3 miles = 5 2-3 miles = 3 1-2 miles = 1 Less than 1 mile = 0	7
31	Proximity to Airport Flight Path	Distance from runway flight path to mitigate risk of exposure to building damage due to plane crash.	More than 3 miles = 5 2-3 miles = 3 1-2 miles = 1 Less than 1 mile = 0	7

Natural Resources IOC Site Evaluations

Site	Location/Land Quality (40%)	Transportation (20%)	Disaster Risk/Recovery (40%)	SCORE	Natural Resource Preliminary Evaluation
Q	54.4	42.6	80	**177**	The southern portion of this site appears to have no habitat conflicts. The northwestern corner includes a small area of mapped hydric soils that may merit investigation, and the eastern boundary abuts wetlands. A site reconnaissance is recommended.
P	54.4	42.6	76.8	**173.8**	A channel running southwest to northeast through the approximate center of the site was noted on maps and aerial photographs of the site. In addition, the forested area southeast of the 'channel' seems to show what may be standing water in some of the images. A closer evaluation of the exact site is needed once the specific parcels are identified.
PGE Sherwood	60.8	40	72.4	**173.2**	In the northeastern corner of the PGE property the base of the east-facing slope most likely supports wetlands. A site reconnaissance to document conditions is recommended.
X	53.6	33.4	81.2	**168.2**	No issues identified. NWI maps a linear wetland feature on the adjacent parcel west of the site. Soils mapped at the site are considered non-hydric, but are known to have hydric inclusions and are in close proximity to hydric soils mapped near the western border of the site. Likelihood of natural resource issues is low.
V	44.8	34.2	87.6	**166.6**	NWI maps show a south-to-north oriented channel originating from the approximate center of the parcel and extending beyond the northern site boundary. Aerial images display evidence to support the presence of this feature. Mapped soils are non-hydric but have known hydric inclusions. The likelihood of jurisdictional wetlands at the site is high, but confined to a narrow area. A site reconnaissance is recommended.

O	49.6	33.2	80.8	**163.6**	The topographically-lower western half of the property is mapped as Labish mucky clay, which is a hydric soil. Historic aerial images seem to show a drainage feature running parallel to the slope base that divides the southeastern portion of the site from the rest. No wetlands are shown on NWI maps, though the potential for wetlands occurring at the site is likely high. A site reconnaissance is highly recommended. A known geologic fault runs through the middle of the property.
R	54.4	38.6	70.4	**163.4**	Along the northeastern border of the site is an extensive wetland area. It is unclear whether this wetland extends onto the undeveloped portions of the site based on our review. A site reconnaissance is recommended.

IOC Site Selection Scoring Activities

Activity	Date
Site Selection Committee identifies key considerations for site selection	January 30, 2018
Site Selection Committee determines process for assessing sites	February 27, 2018
Site Selection Committee agrees on scoring categories and criteria	March 7, 2018
Site Selection Criteria and Scoring Template provided to Broker for assessment of available sites	March 7, 2018
Broker provides assessment/scoring of available sites to PGE	April 13, 2018
Site Selection Committee elects to narrow list of sites under consideration to the top 7 by score	April 18, 2018
PGE Environmental Services performs natural resources assessment on 7 sites and recommends elimination of 2	April 30, 2018
Site Selection Committee eliminates PGE-Sherwood and Site 'O' based on recommendation of internal natural resources assessment	May 3, 2018
Broker tour of 5 Sites – Dreyfuss + Blackford/SERA Architects and PGE	May 11, 2018
Site Selection Committee eliminates sites 'R' and 'X' from further evaluation and submits finalist sites to design team for assessment	May 16, 2018
Project Architect/Engineer delivers report recommending optimal site for IOC	June 29, 2018

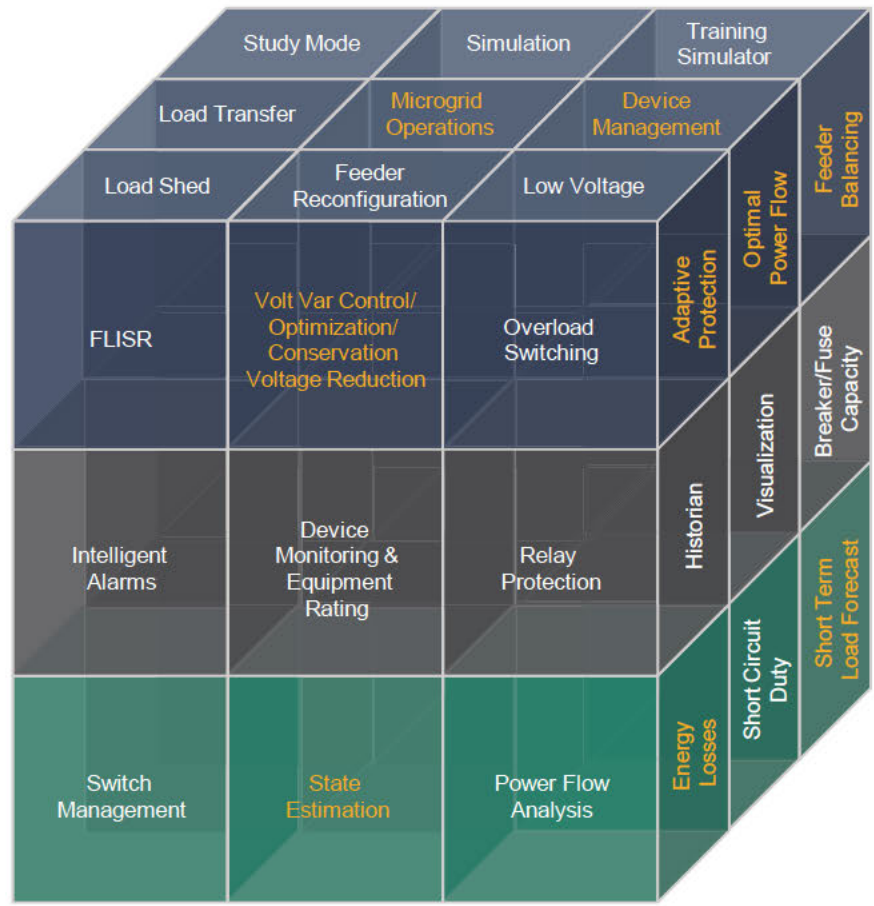
ADMS

Core Functionalities (Cube)

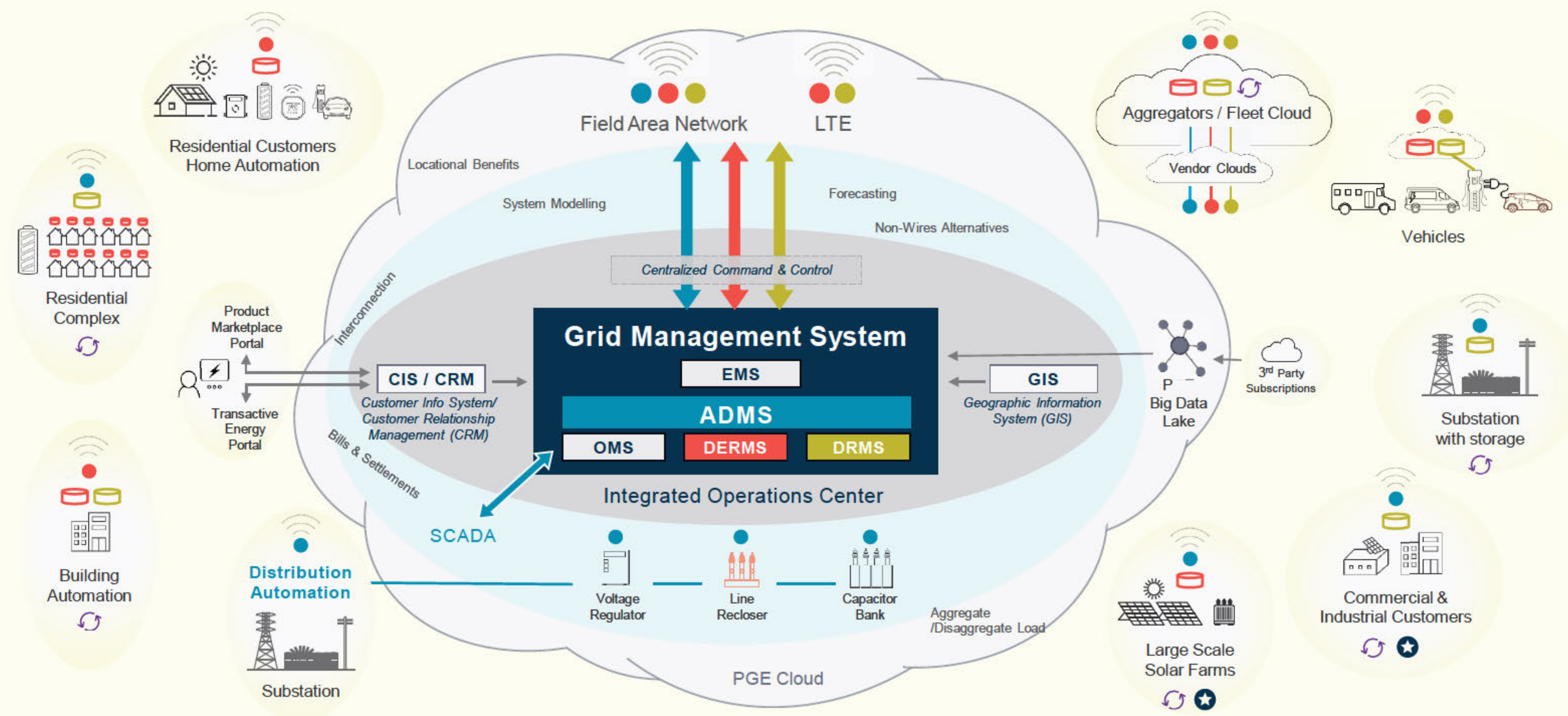
Control

Monitor

Predict

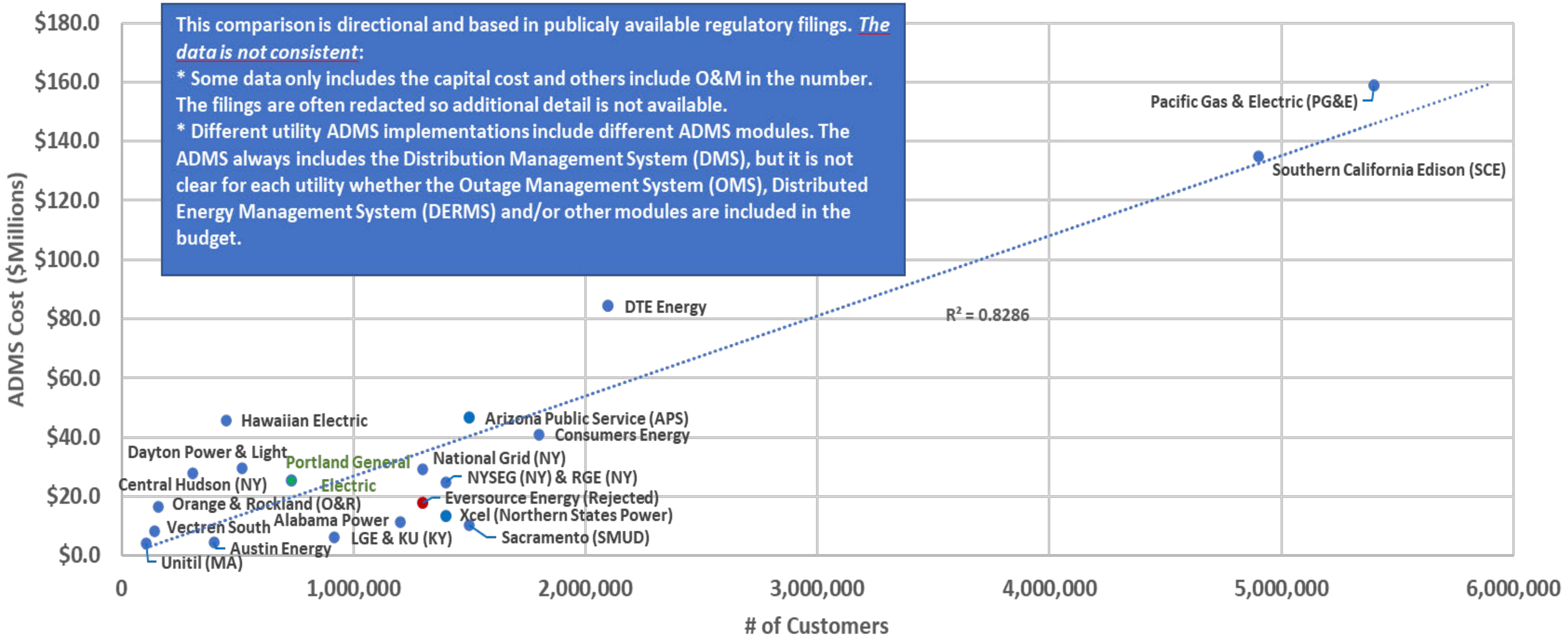


PGE Grid Modernization – Conceptual Overview of the Grid



KEY Potential µGrid / Microgrid Potential Qualified Facility Demand Response Mgmt System (DRMS) Distributed Energy Resource Mgmt System (DERMS) Node communicating with system 1-way or 2-way communication through Vendor, Aggregator, or direct to PGE

ADMS Budgets by Size of Utility



Reference ADMS Budgets

Utility	# of Customers	Cited ADMS Budget (in $M)*	Reference
Unitil (MA)	105,000	$4.3	https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12002865
Austin Energy	400,000	$4.5	http://www.austintexas.gov/edims/document.cfm?id=187122
LGE & KU (KY)	915,000	$6.2	https://psc.ky.gov/pscecf/2018-00295/derek.rahn%40lge-ku.com/09282018081716/10_-_LGE_Testimony_and_Exhibits_1_of_3.pdf
Vectren South	142,000	$8.2	https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/0ff57db2-fff9-e611-8104-1458d04e8ff8/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=44910_Vectren%20South_No%201_Direct%20Testimony%20and%20Attachments_Luttrell_022317.pdf&folderPath=
SMUD	1,500,000	$10.2	https://www.smud.org/-/media/Documents/Corporate/About-Us/Board-Meetings-and-Agendas/2018/Feb/2-Lora-Anguay--OSI-Inc-Contract.ashx?la=en&hash=4D7BD5474726600E86F59CD932AFD04F3774F374
Alabama Power	1,200,000	$11.3	https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=8&ved=2ahUKEwizjrGct_HiAhXict8KHZ0tARkQFjAHegQIARAC&url=https%3A%2F%2Fwww.osti.gov%2Fservlets%2Fpurl%2F1133631&usg=AOvVaw1kcaJGAutdaUpYoS2SSGcj
Xcel (Northern States Power)	1,400,000	$13.4	https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BE098D466-0000-C319-8EF6-08D47888D999%7D&documentTitle=201811-147534-01
O&R	158,378	$16.4	https://www.oru.com/_external/orurates/documents/ny/testimony-and-exhibits-eiop-1-eiop-5.pdf
Eversource Energy (Rejected)	1,300,000	$17.7	https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9220907
NYSEG (NY) & RGE (NY)	1,400,000	$24.8	http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B5D4D0DE0-4496-407B-8A3D-5A1D6E9E929D%7D
Portland General Electric	735,500	$25.3	
Central Hudson (NY)	307,000	$27.7	http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=210049&MatterSeq=45894
National Grid (NY)	1,300,000	$29.2	¡http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B2CEE1834-9550-4578-AF3B-BFF28F0F0A23%7D
Dayton Power & Light	520,000	$29.4	http://dis.puc.state.oh.us/TiffToPDf/A1001001A18L21B73022B03052.pdf
Consumers Energy	1,800,000	$41.0	https://www.consumersenergy.com/-/media/CE/Documents/rates/case-number-20134-exhibits-part-2.ashx
Hawaiian Electric	450,000	$45.8	https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A19J01B05653A00075
Arizona Public Service (APS)	1,500,000	$46.5	https://images.edocket.azcc.gov/docketpdf/0000170846.pdf
DTE Energy	2,100,000	$84.3	https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UWzpAAG
Southern California Edison	4,900,000	$135.0	http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/49FCCC4EB70514FB882580210068F69D/$FILE/SCE02V10.pdf
Pacific Gas & Electric (PG&E)	5,400,000	$158.6	https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=545405

*Data represented do not represent consistency across utilities; Some are product cost; some are complete costs.

Portland General Electric

2021 Wildfire Mitigation Plan

PGE

Internal Use

Wildfire Mitigation Program & Contact Information

TABLE 1: LIST OF EXTERNAL-FACING CONTACTS

Department	Persons
Government Affairs	Randy Ealy (LGA) Sunny Radcliffe (GA)
Communications Spokespeople	On duty answering service (503-251-4099) Brianne Hyder
IMT Resource	Jay Jewess (503-464-8035)
Emergency Management	Jay Jewess
Key Customer Management	Kimberly Donahue Steven Binder

TABLE 2: LIST OF INTERNAL-FACING CONTACTS

Department	Persons
Director, Wildfire Resiliency and Mitigation Director	Bill Messner
Director, Operations	Tom Yost
Legal	Derily Bechthold
Communications	Brianne Hyder
Business Continuity & Emergency Management	Jay Jewess
Manager, Wildfire Mitigation Program Management	Michael Ansbergs
Senior Manager, Strategic Asset Management, Wildfire Mitigation	Jay Landstrom

Revisions Log

The following table details the nature, date, and primary author of major revisions to this document. All impactful revisions – revisions that make significant changes to PGE Wildfire Mitigation strategies, roles or responsibilities -- must be reviewed and approved by appropriate management signatories (listed in the "Approved By" table, below), as well as the reviewers listed in the "Reviewers" table, below.

TABLE 3: REVISIONS LOG

Date	Version	Revision Description	Author
05/28/2021	0.1	Initial Draft	Jeff Kuechle

TABLE 4: REVIEWER LOG

The table below lists initial reviewers of PGE's Wildfire Mitigation Plan. Once it has been approved, all changes to this document (other than minor wordsmithing) shall be approved by the original reviewers and logged below.

Review Date	Version	Reviewer Role	Reviewer
6/1/21	Final Draft	Wildfire Mitigation and Resiliency	Bill Messner
5/11/21	Draft	Wildfire Mitigation and Resiliency	Mike Ansbergs
5/11/21	Draft	Wildfire Mitigation and Resiliency	Jay Landstrom
5/11/21	Draft	Operations	Tom Yost
5/28/21	Final Draft	Legal	Derily Bechthold
5/11/21	Draft	Corporate Communications	Brianne Hyder
5/11/21	Draft	Government Affairs Local Government Affairs	Brooke Brownlee Randy Ealy
5/11/21	Draft	Rates and Regulatory Affairs	Nidhi Thakar Stefan Brown
5/28/21	Final Draft	SVP, Advanced Energy Delivery	Larry Bekkedahl
6/1/21	Final Draft	VP, Utility Operations	Bradley Jenkins

TABLE 5: APPROVED BY

Date	Version	Approved By	Signature
		Larry Bekkedahl Senior VP, Advanced Energy Delivery	Larry Bekkedahl Larry Bekkedahl (Jun 4, 2021 16:10 PDT)
		Bradley Jenkins Vice President Utility Operations	Brad Jenkins (Jun 4, 2021 16:00 PDT)
		Bill Messner Director Wildfire Mitigation & Resiliency	W. M. Messner W. M. Messner (Jun 4, 2021 15:35 PDT)

Table of Contents

Section 1. Introduction

The number and severity of recent wildfire[1] events throughout the western United States have increased awareness of the role that utilities play in wildfire prevention, mitigation, and response. Portland General Electric (PGE) understands that we have a critical role in reducing the risk of wildfires caused by electrical equipment or grid maintenance activities. We are approaching this issue with urgency to minimize the risk of our facilities creating or contributing to public safety hazards. Our communities expect us to help keep them safe and out of harm's way. PGE's dynamic approach to wildfire mitigation emphasizes continuous improvement through in-season situational awareness and post-season review processes.

PGE takes this responsibility seriously because wildfire mitigation faces multiple challenges in the 21st century. Even in our famously cool and rainy region, winters have become measurably drier, summers longer-lasting and hotter. We can no longer count on what the Pacific Northwest once thought of as "normal:" a wildfire season that started in July and was extinguished by the rains of October. Rapidly changing weather patterns, driven by climate change, have increased both the likelihood and intensity of wildfires. Rapid expansion of many cities and suburbs into the wildland-urban interface (WUI) has increased both the number of structures and the amount of electrical infrastructure located in forested areas.

PGE encourages regional policymakers to continue to effectively address the growing magnitude of the regional wildfire threat – and stands ready to help. Despite the fact that few wildfires are ignited by utility infrastructure – of Oregon's 983 wildfires in 2020, none have been confirmed to be caused by power lines -- PGE is supportive of the work of the Governor's Wildfire Council and the legislature are doing to address the growing magnitude of wildfire threat throughout the state. This includes the recommendation that utilities operate in compliance with risk-based wildfire protection plans approved by the Public Utility Commission.

As a company, PGE must be able to move quickly and efficiently to reduce the risk that PGE equipment (including PGE-owned and operated equipment outside our service territory), facilities and activities contribute to wildfire danger within PGE's service territory. PGE takes this responsibility seriously; many elements of PGE's wildfire mitigation program, such as its Advanced Wildfire Risk Reduction (AWRR) program, significantly exceed regulatory requirements.

In an ongoing effort to be aggressively proactive in our preparation for the 2021 fire season, PGE is utilizing all available resources to identify high-risk areas that may be impacted by wildfires, which has resulted in a significant expansion of PGE's PSPS areas. Due to the extensive time and effort required to prepare for the upcoming fire season, not all work identified in this Plan will be completed in advance of fire season. This includes our enhanced vegetation management and inspection work which is impacted by the significant increase in coverage area. This work is on-going, and the identified PSPS areas may continue to expand or be impacted by the issuance of the State of Oregon's fire map. The identified PSPS zones will be evaluated on an ongoing basis due to changing conditions and will likely change over time, so PGE must be flexible in

[1] A wildfire is defined as "an unplanned fire burning in natural (wildland) areas such as forests, shrub lands, grasslands or prairies" by the US Forest Service.

order to meet evolving needs, and transparent about what is possible for us to achieve in these areas, in order to clearly manage expectations regarding completion of pre-season work.

To successfully implement all the enhanced vegetation, inspection, and system resiliency updates planned in the seven PSPS Zones, PGE must take a phased approach that includes:

- Securing additional funding to support the cost of completing the mitigation work
- Once funded, operationalizing the enhanced wildfire mitigation work plans, which includes increasing labor resources to perform the work in expanded coverage areas, and
- Developing a schedule to complete the work in future years.

The following list shows which Vegetation Management items PGE will complete in 2021:

- 100% P1 (trees that present an imminent risk to either nearby power lines, or to the work area being used to repair lines) inspection and mitigation by July 1 (all PSPS overhead line mileage)
- Mt Hood PSPS Zone 1:
    - P1 Inspection: During June 1/June 2 patrol.
        - P1 vegetation will be addressed within 24 hours of identification.
        - Hotspot trimming (vegetation within 5 feet of PGE facilities): completed within two weeks of patrol.
- 275 miles of additional P2 (trees that are damaged or diseased and could fall into nearby power lines, but do not pose an imminent risk) scoping (full AWRR scope in PSPS Zones 1,4,5)
    - Starting in July, PGE will work through the year and through 2022
    - This work will target PSPS feeders where there is a favorable customer base and low/no local or county permit restrictions on our vegetation management work.

PGE is initiating the required work (PSPS requirements, annual line patrols, hazard removals) on time, but some areas in the high-risk (PSPS) zones will not receive full AWRR treatment in 2021 – instead, PGE will phase in this enhanced mitigation work over several years. PGE's enhanced inspection work will be complete for the seven PSPS Zones by the end of 2021. Again, the plan may change further when the state of Oregon issues its fire map, which may alter PGE's PSPS Zones

This Plan and its appendices (most restricted to PGE internal use only) describe PGE's approach to the prevention and mitigation of wildfires: the organizations responsible, purpose and scope, and the objectives and specific actions PGE will take in 2021 to safeguard customers, employees and facilities in Oregon while ensuring compliance with OPUC wildfire rules and requirements. PGE will annually re-evaluate its fire season operations and wildfire mitigation preparedness and response actions, as well as regulatory requirements, and update this plan in response.

Section 2. Persons Responsible for Preparation & Execution of the Wildfire Mitigation Plan

PGE formalized its longstanding wildfire mitigation planning efforts through the establishment of its Wildfire Mitigation & Resiliency (WM&R) organization following the extremely challenging 2020 wildfire season, which saw "numerous large fires resulting in fatalities and significant property losses in Oregon," 3,831 structures destroyed and a total burned acreage that was more than double the 10-year average for the Northwest region[2].

PGE's WM&R and Business Continuity & Emergency Management (BCEM) organization are primarily responsible for coordinating PGE's wildfire-related strategic planning, preparedness and engagement across multiple internal and external organizations. WM&R's internal partners, which include Vegetation Management, Strategic Asset Management and Utility Asset Management, Operations, Customer Service and Brand Marketing and Communications, have responsibility for wildfire-related preparedness, operational, incident response, communications and outreach and recovery activities.

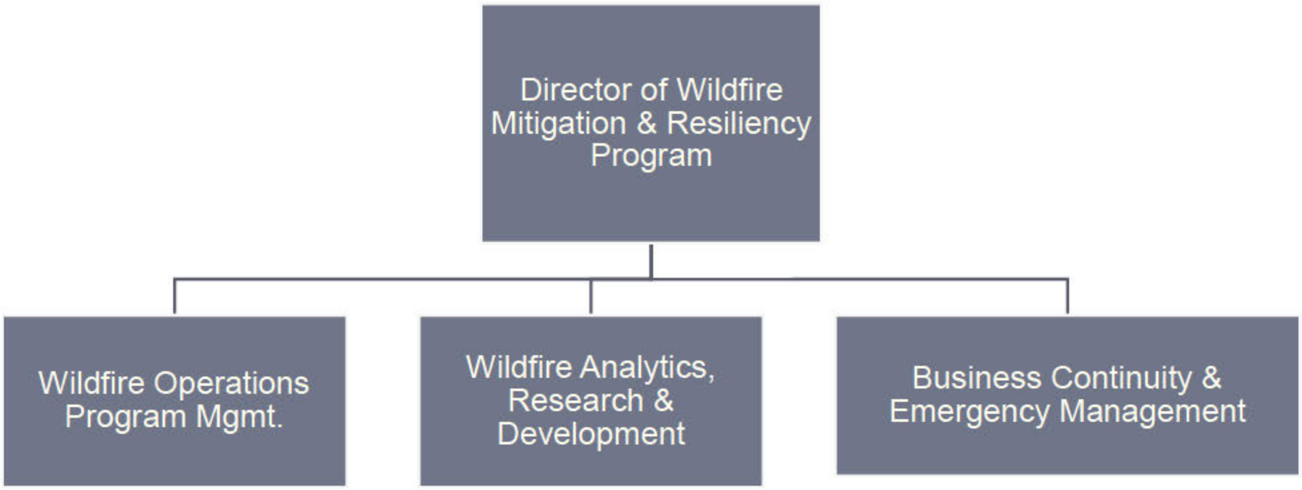
To ensure a comprehensive and integrated approach to wildfire prevention and management, PGE has organized its wildfire mitigation strategy around six program areas:

- Vegetation Management
- Asset Management & Inspections
- Risk Management
- Operating Protocols
- Stakeholder Engagement
- Research & Development

Together, these six programs organize PGE's wildfire preparedness and response activities into logical categories, allowing PGE to take a systematic approach to this complex challenge. Each program "track" addresses a key aspect of wildfire risk assessment, preparedness, prevention, mitigation, response or training. This comprehensive and interconnected approach derives its effectiveness from the expertise of multiple individuals and organizations across PGE, as well as strong coordination and collaboration with external stakeholders. Its success relies on the participation and buy-in of all PGE personnel.

[2] Source: National Interagency Coordination Center's Wildland Fire Summary and Statistics 2020 Annual Report

FIGURE 1- WILDFIRE MITIGATION & RESILIENCY ORGANIZATIONAL CHART



Wildfire Mitigation Programs and Activities Responsibilities

The following table provides an overview of the organizations and individuals responsible for the implementation of various aspects of PGE's wildfire preparedness, mitigation, and response program:

TABLE 7: PGE WILDFIRE MITIGATION ROLES AND RESPONSIBILITIES

Program	Responsible Group	Responsible Position
Vegetation Management	• Vegetation Management	• Manager, Vegetation Management • Manager, Forestry
Asset Management & Inspections	• Strategic Asset Management • Utility Asset Management • System Health & Maintenance	• Senior Director, Utility Ops • Senior Director, Engineering Services
Risk Management	• Wildfire Analytics Research & Development • Strategic Asset Management	• Senior Manager, Wildfire Analytics Research & Development • Senior Director, Engineering Services

Operating Protocols	• Wildfire Mitigation & Resiliency • Utility Operations • Grid Operations • Safety • Generation, Transmission & Distribution Project Management Office • Corporate Communications • Engineering • Environmental, Health & Safety	• Director, WM&R • Senior Director, T&D Operations • Director, Grid Operations • Senior Director, Program Operations Support, Construction Management • Senior Director, Corporate Communications • Senior Director, Engineering Services • Senior Director, Environmental Services
Stakeholder Engagement	• Wildfire Mitigation & Resiliency • Corporate Communications • Government Affairs • Key Customer Management	• Director, WM&R • Senior Director, Corporate Communications • Manager, Government Affairs • Manager, Local Government Affairs • Outreach Director
Research & Development	• Wildfire Analytics Research & Development	• Senior Manager, Wildfire Analytics Research & Development

Section 3. Purpose and Scope

This Wildfire Mitigation Plan was developed to provide strategic direction to the programs and activities that minimize the potential for PGE equipment, facilities or activities to become wildfire ignition sources, as well as guidance for PGE's wildfire-related interactions with external stakeholders. It includes key principles guiding the implementation of PGE's wildfire prevention and mitigation program, including:

- Ensure public and employee safety
- Act with urgency to reduce the risk of wildfire ignitions, to respond to wildfire events, and to recover from incidents
- Communicate and collaborate effectively with energy partners, agencies, counties, federal, state and local governments, communities, and customers
- Maintain reliable electric service
- Utilize a systematic, risk-based approach to identify and prioritize system hardening and resiliency efforts

PGE's Wildfire Mitigation Plan demonstrates PGE's commitment to the prevention and mitigation of wildfire events through a program that is supported by many different organizations within PGE. This Plan describes specific preparedness and response responsibilities, by organization, to guide an integrated approach to achieving PGE's wildfire-related safety goals.

Section 4. Wildfire Risk Mitigation Objectives

The overall objective of PGE's Wildfire Mitigation Plan is to reduce wildfire risk for PGE customers, communities and PGE, while limiting the impacts of specific mitigation activities, such as Public Safety Power Shutoffs (PSPS), on customers. Other objectives of this Plan include:

- Document PGE strategies and activities that will ensure public and employee safety through mitigation actions
- Act with urgency to mitigate risk of wildfire ignition, to respond to and reduce the severity of wildfire events, and to recover from incidents
- Collaborate with energy partners, first responders, agencies, counties, federal, state and local governments, communities, and customers to prevent and respond to wildfire events
- Ensure effective external communications before, during and after wildfire events impacting PGE and its customers
- The implementation of a systematic, risk-based approach to identify and prioritize system hardening and resiliency measures
- Strengthening internal and external organizational partnerships to increase trust and improve coordination of emergency response activities, and situational and conditional awareness
- Improve wildfire planning, prevention and response through coordination, communication, and collaboration with external stakeholders
- Improve guidance on operational activities related to wildfire prevention, response and critical infrastructure security and resilience
- Continuous improvement of PGE's wildfire-related risk management and situational awareness capabilities
- Pre-planning of effective, mutually beneficial, coordinated responses to prevent incidents, save lives and facilitate rapid recovery from wildfire events
- Promotion of learning and adaptation during and after wildfire-related exercises and incidents.

Section 5. Strategic Alignment / Risk Management Approach

In 2019, PGE embarked on a multi-faceted wildfire risk assessment and modeling approach, developed in two phases:

- **Phase 1**: Evaluated industry best practices, using publicly available information to assess the in-situ risk of Transmission & Distribution (T&D) assets of causing wildfire ignition, and defined Tier 2 (Elevated) and Tier 3 (Extreme) wildfire risk areas within PGE's service territory, using the analytical methodology developed by the U.S. Forest Service and California Department of Forestry and Fire Protection.
- **Phase 2**: Increased the granularity of the Phase 1 risk assessment by factoring in the likelihood of individual PGE facilities causing wildfire ignition, quantifying where individual PGE assets are most likely to ignite a wildfire, and incorporated a consequences model that identifies where a PGE-caused wildfire ignition would be most impactful (>100 hectares). Developed a statistical model

integrating ignition probability and consequences data to produce a cost/benefit analysis of specific wildfire mitigation actions. Model results were one of the factors used in the development of PGE's 2021 wildfire mitigation program.

The purpose of this analysis is to analyze PGE's susceptibility to the natural and human factors that contribute to utility-caused wildfire ignition, and to provide empirical guidance for PGE's wildfire mitigation program -- specifically, how to allocate available resources to yield maximum wildfire risk reduction benefit. PGE's goal is to make our communities, customers, employees and facilities safer by measurably reducing the probability of wildfires ignited by electric utility equipment or activities.

To evaluate engineering, construction and operational strategies to reduce the risk of wildfires associated with electrical facilities, PGE leveraged model data, as well as lessons learned from previous fire seasons, recommendations from regional wildfire stakeholders and partners, and the Oregon Public Utility Commission guidance and rulemaking. The following core concepts were used to guide this evaluation:

- Frequency of ignition events attributable to electric facilities can be reduced through effective vegetation management, inspection and maintenance of poles and equipment, and by engineering more resilient systems that experience fewer fault events
- When a fault event does occur, the impact of the event can be minimized through effective use of equipment and personnel to swiftly isolate and correct the fault
- Systems that maximize situational awareness and operational readiness are crucial to mitigating wildfire risk and its impacts

A successful Wildfire Mitigation Plan must consider impacts to customers and other stakeholders, as well as PGE's ability to provide safe, affordable and reliable electric service. It must be proportional to the risks specific to PGE's service area and customer base. In 2021, PGE is using the results of its Phase 2 wildfire risk assessment to implement the following specific mitigation measures:

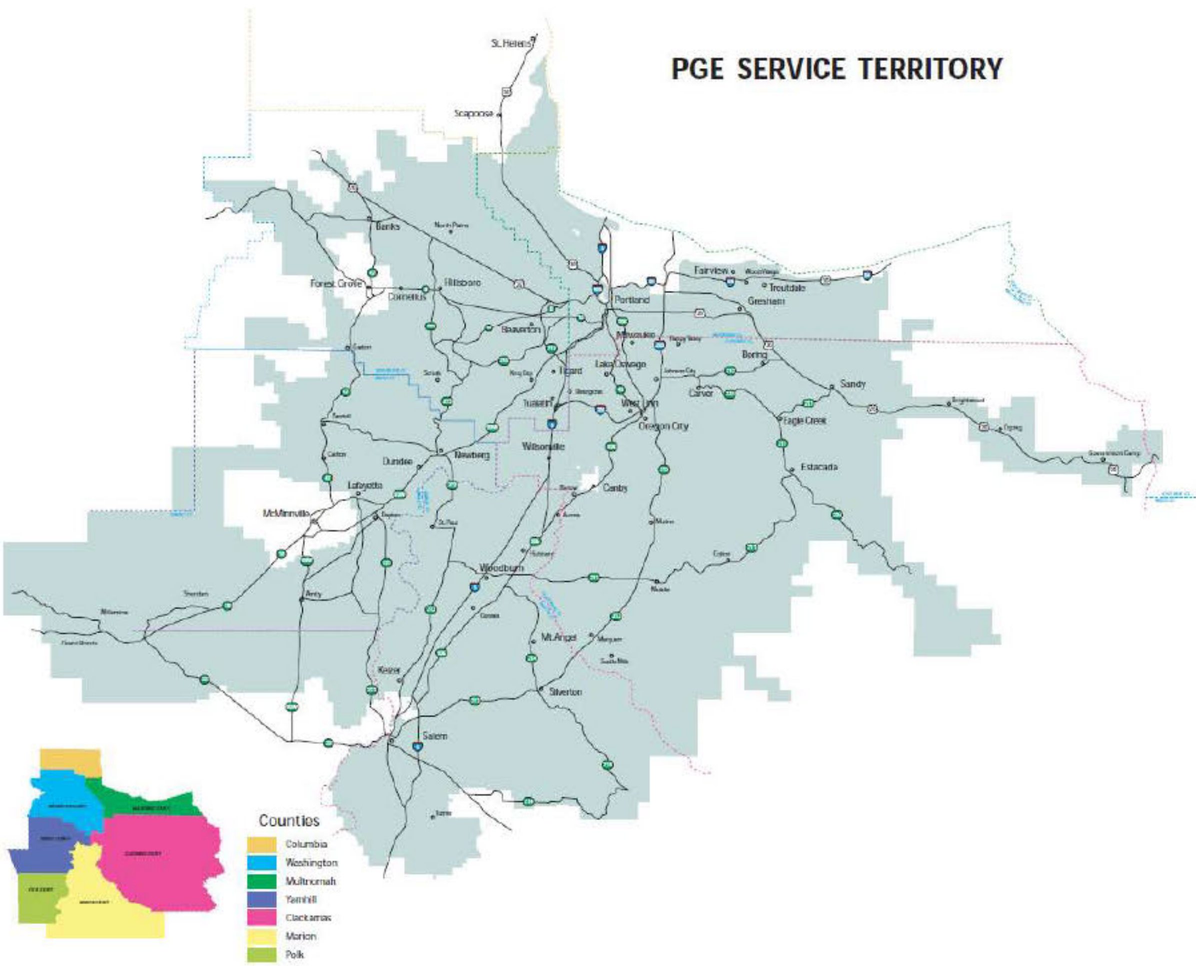
- In addition to its existing Mt. Hood Corridor Public Safety Power Shutoff (PSPS) zone, PGE has identified six new PSPS Zones in PGE's service territory with higher risk of utility-caused wildfire
- PGE is deploying enhanced wildfire risk inspection and Advanced Wildfire Risk Reduction (AWRR) vegetation management programs in all seven PSPS zones, significantly expanding the footprint of PGE's 2020 vegetation management program
- Installation of additional weather stations to increase PGE situational awareness
- Implementation of new technology, including early fault detection systems, advanced reclosers and protection schemes, and smart faulted circuit indicators (FCIs) on PSPS feeders
- Installation of additional non-expulsion fuses on feeders in PSPS zones
- Strategic use of ductile iron poles on PSPS feeders: when poles are replaced or added in high-risk areas, PGE will replace them with ductile iron poles unless the material is unavailable, in which case PGE will use wood poles. Secondary wood poles will continue to be replaced with wood on an as-needed basis.

Due to the significant increase in identified high risk areas these efforts must cover, enhanced work in these areas will not be complete pre-fire season and will continue beyond the 2021 fire season.

Section 6. Operating Environment

For more than 130 years, PGE has empowered the pioneering spirit of our region, generating and distributing energy safely, reliably and responsibly. Our service area covers 51 cities, six counties and approximately 4,000 square miles. PGE interconnects with multiple neighboring utilities, including the Bonneville Power Administration (BPA), PacifiCorp, West Oregon Electric Cooperative, Wasco Electric Cooperative, and Consumers Power, Inc. Much of the eastern portion of PGE's service area is forested, particularly in the Mt. Hood corridor along Highway 26, and south toward Estacada along Highway 212. In all, PGE's operating environment contains more than 2 million trees to be managed directly in PGE's right-of-way (ROW), with significantly more immediately adjacent to PGE's ROW.

FIGURE 2: PGE SERVICE TERRITORY



6.1. Risk Zones (High Fire Threat)

For the purposes of this Plan, PGE Wildfire Mitigation, Operations and field staff will refer to high wildfire risk PSPS Zones to indicate areas of the PGE service territory where vegetation, terrain, and wildland-urban interface (WUI) infiltration increase the risk of utility-caused wildfire ignition. In 2021, PGE has identified seven potential PSPS Zones:

Zone 1: Mt. Hood Corridor/Foothills

Zone 2: Columbia River Gorge

Zone 3: Oregon City - S. Redland

Zone 4: Estacada - Faraday

Zone 5: Scott's Mills

Zone 6: Portland West Hills

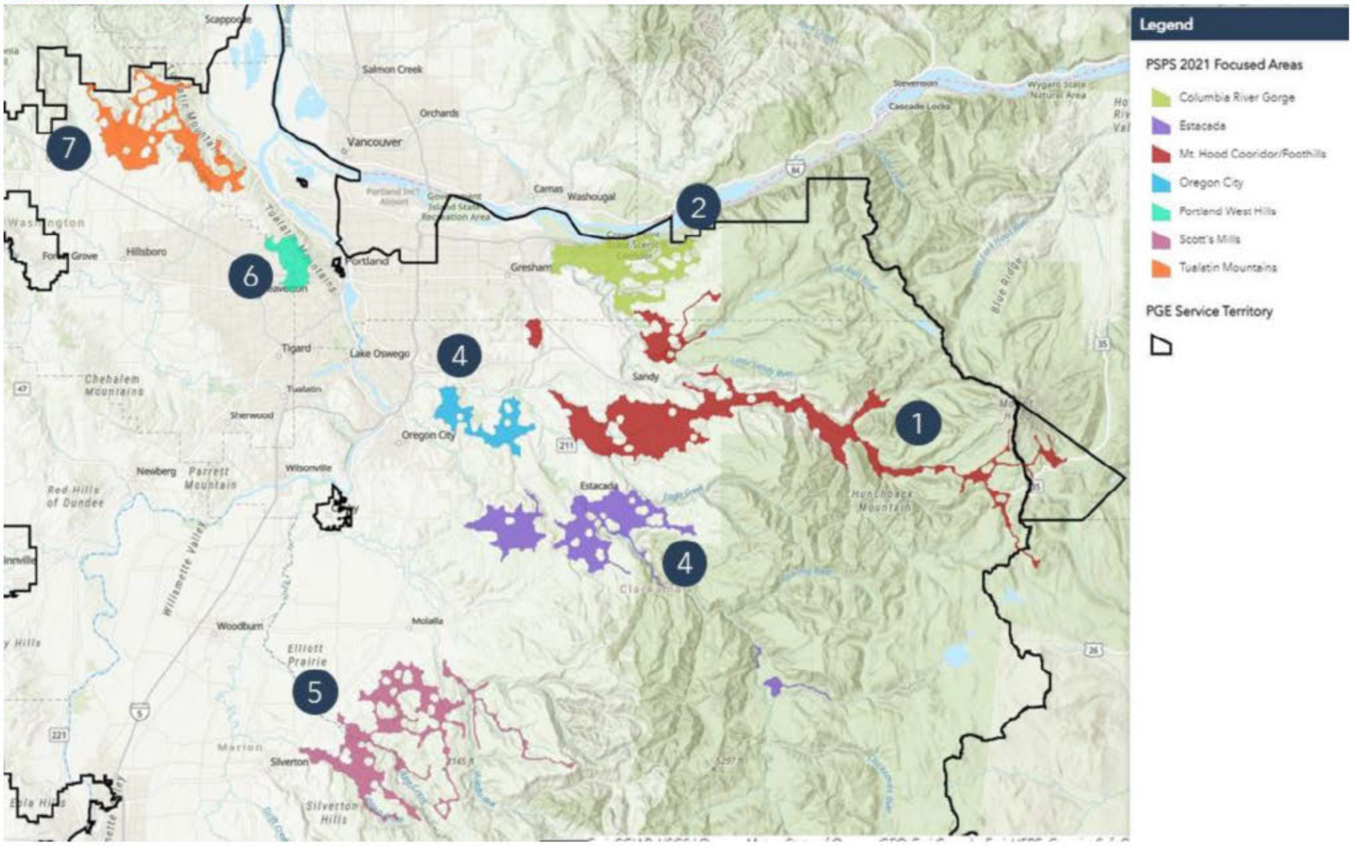
Zone 7: Tualatin Mountains

Results of PGE's Phase 1 and Phase 2 risk analysis indicate that the majority of PGE's wildfire ignition risk is concentrated in the WUI sections of its service territory. The results also show that vegetation impingement and animal contact are the leading sources of PGE's utility-caused wildfire ignition risk. In response to these findings, PGE has significantly expanded its wildfire inspection and AWRR programs, deploying vegetation management and maintenance crews throughout the highest-risk areas of its service territory. Due to the significant increase in areas these programs must cover, enhanced work in these areas will not be complete pre-fire season and will continue beyond the 2021 fire season.

In 2021, PGE began implementation of expanded vegetation management activities to ensure that all 777 circuit-miles of PGE overhead infrastructure within the seven PSPS Zones receive enhanced inspection and vegetation management. These efforts although initiated in 2021 will not be complete and will be phased-in in subsequent years. These high wildfire risk areas also include certain areas around PGE's Central Oregon transmission and distribution facilities. In addition, PGE is deploying circuit breaker and recloser protection measures in identified PSPS Zones to minimize fault energy and reduce the risk of ignition during wildfire season.

PGE will also actively share our PSPS zones with local and state agencies. These conversations will be incorporated into our decision making and may result in expanding or modifying these existing zones or identifying new areas based on agency input.

FIGURE 3: 2021 PGE PSPS ZONES



Section 7. Wildfire Risk Mitigation Programs & Activities

The overall objective of PGE's risk mitigation program is to reduce wildfire risk for the utility, our customers and the communities we serve, and to limit the impacts of wildfire risk reduction strategies, such as PSPS, on customers. PGE's risk models assess the probability of equipment starting a wildfire, as well as the potential consequences of a wildfire ignited by an individual asset, to prioritize wildfire inspection and maintenance schedules and capital remediation programs. PGE also uses geographic risk (georisk) modeling to identify where the risk of vegetation-triggered wildfire is highest, and prioritizes vegetation management and maintenance activities accordingly.

The US Forest Service defines the WUI as the zone of transition between unoccupied land and human development -- the line, area or zone where structures and other human development meet or intermingle with undeveloped wildland and vegetative fuels. Results from PGE's Phase 1 and 2 risk assessment process indicate that the majority of PGE's wildfire risk is concentrated in the WUI sections of PGE's service territory; they also indicate that the risk of ignition from PGE equipment is similar to other utilities' risk. Again, model results show that vegetation impingement and animal contact with T&D assets are the leading sources of PGE's utility-caused wildfire ignition risk.

These findings are impacting PGE's 2021 Wildfire Mitigation Program in multiple key areas. Among other measures, PGE is:

- Utilizing light detection and ranging (LiDAR) and hyperspectral imaging (a technology that uses a wider color spectrum to provide more information on what is imaged) results from a 2019 survey project across our entire service territory, to identify areas where risk is concentrated due to vegetation proximity to transmission and distribution infrastructure. Because most utilities lack aerial LiDAR capability, PGE is ahead of its industry peers with respect to vegetation analysis technology. LiDAR survey data must be updated every three to five years.

- Significantly expanding its wildfire inspection and maintenance and AWRR programs to include annual inspection of 100 percent of the assets in all seven PSPS Zones, as well as key portions of its Central Oregon transmission and distribution system.
- Deploying vegetation management and maintenance crews throughout the highest-risk areas of its service territory prior to the declaration of the 2021 wildfire season.
- Installing ductile iron poles and initiating a fire-retardant pole wrap pilot program, to replace and protect flammable wood poles in key portions of its PSPS Zones
- Replacing avian protection devices (non-conductive covers that prevent birds from contacting energized equipment, which research has shown could be an ignition source) in PSPS Zones
- Installing advanced reclosers and protection schemes to prevent wildfire ignition following fault events, as well as additional non-expulsion fuses, on high-risk feeders
- Testing new fire detection and prevention technology, such as high-impedance fault detection, downed conductor detection, early fault detection systems, and “smart” faulted circuit interrupters.

7.1. Risk Management

In 2019, PGE embarked on a multi-phase risk assessment and modeling program to evaluate industry best practices, identify the highest wildfire risk areas within the PGE service territory, quantify the likelihood that individual PGE assets could contribute to wildfire ignition, map their location, and apply a consequences model to determine where a PGE-caused wildfire ignition would be most impactful. This statistical model integrating ignition probability and consequences data enabled a cost/benefit analysis to help prioritize specific wildfire mitigation actions. These model results were a key input to the development of PGE’s 2021 wildfire mitigation program.

7.1(a) Roles & Responsibilities

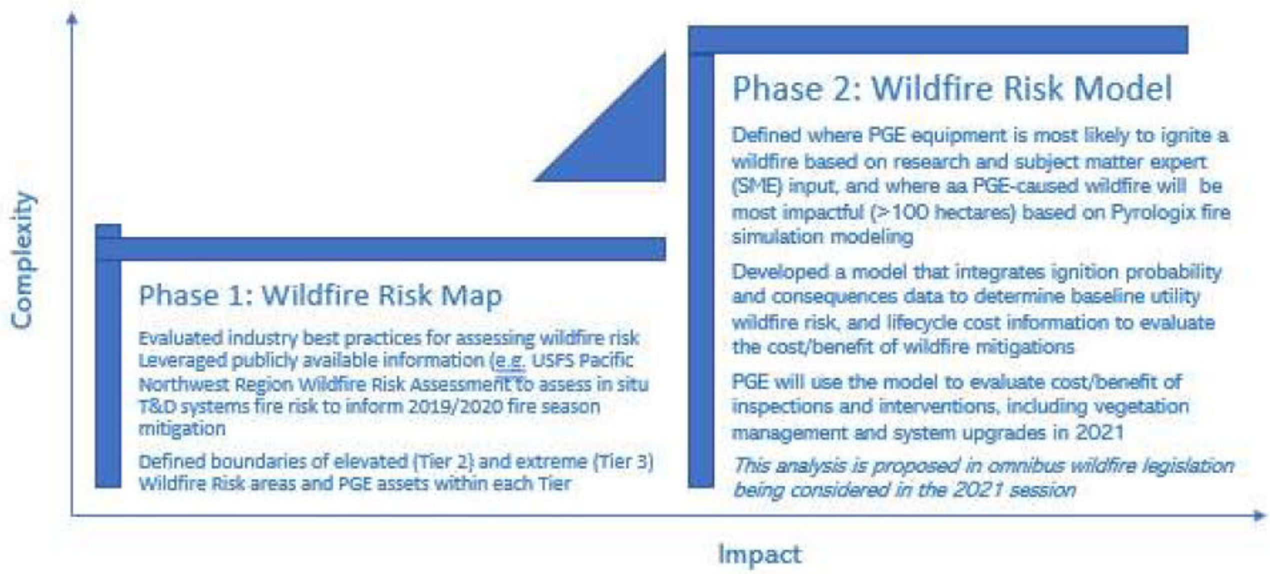
Strategic Asset Management Manager, Strategic Asset Management	Define methodology for identifying and evaluating wildfire-related risk
	Identify where PGE’s equipment is most likely to ignite a wildfire and where a PGE-caused wildfire would be most impactful (>100 hectares, >400 hectares), and develop a model to determine baseline utility wildfire risk and enable systematic evaluation of the cost/benefit of potential wildfire mitigations
	Develop an initial wildfire risk assessment framework, identifying PSPS Zones throughout the PGE service territory to inform mitigation measures
	Deliver the remote sensing project and investigate opportunities to enhance the wildfire risk assessment model by integrating high-fidelity remote sensing data to identify trees that could pose a threat to PGE’s system and target them for remediation

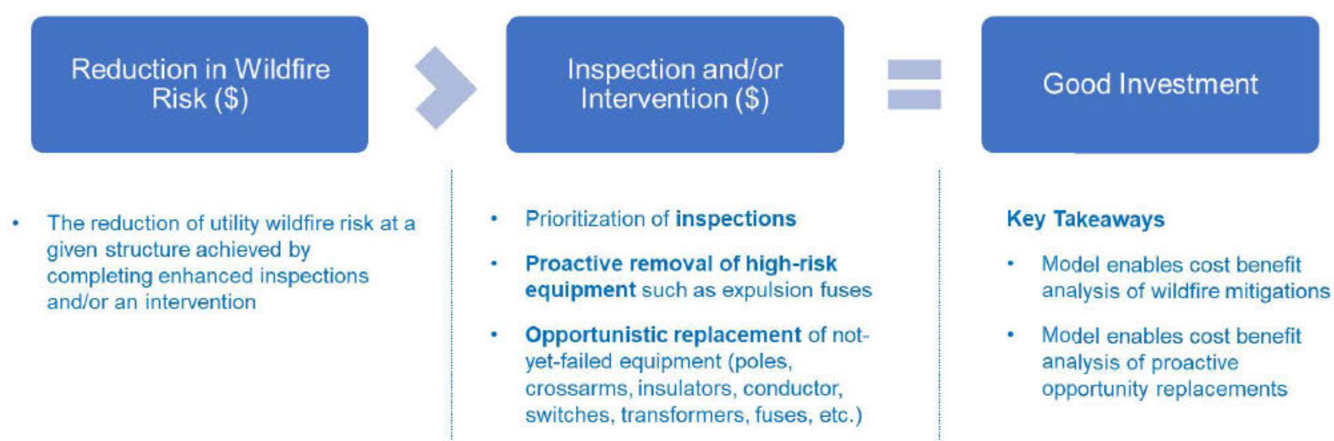
	Investigate improvements to datasets and analytical techniques to evolve the initial wildfire risk assessment framework into a wildfire risk assessment model and integrate fire risk into the overall asset and risk management frameworks
	Build strategic partnerships to improve wildfire risk assessment

7.1(b) Risk Assessment Approach & Current Understanding

1. Risk Overview

FIGURE 2 OVERVIEW OF PGE'S PHASED APPROACH TO WILDFIRE RISK ASSESSMENT





(ii) Baseline Utility Wildfire Risk

Probability

Ignition probability is the annual likelihood that a given piece of equipment will ignite a wildfire given its type, age, condition, and location. In most cases, probability varies with age, increasing as equipment ages and is more likely to fail. The values shown in Table are for 40-year-old equipment. The higher the Ignition Probability value, the more likely that Source of Ignition is to become a wildfire ignition source.

TABLE 8: SUMMARY OF ANNUAL IGNITION PROBABILITY

Source of Ignition	Ignition Probability (K_{SP})	Probability Varies with Age?	Probability of Violation or Damaged	Multiplier if Violation or Damaged
Vegetation	7.4	No	1.3%	4.4
Animal	5.9	No	NA	NA
Fuse	4.6	Yes	small	NA
Lightning arrestor	2.8	Yes	5.0%	2.5
Secondary	2.1	Yes	1.2%	2.8
Crossarm	1.5	Yes	5.1%	5.6
Conductor	1.3	Yes	0.4%	1.9
Switch	1.3	Yes	10.0%	3.0
TX Switch	1.3	Yes	10.0%	3
Recloser	0.87	Yes	10.0%	11.4
Structure	0.86	Yes	2.0%	4.3
Capacitor	0.79	Yes	10.0%	11.4
XFMR	0.74	Yes	small	11.4
Insulators	0.52	Yes	2.9%	3.2

Figure 5 illustrates equipment-specific wildfire ignition risk within PGE's geographic footprint. Yellow, orange, and red dots indicate elevated risk.

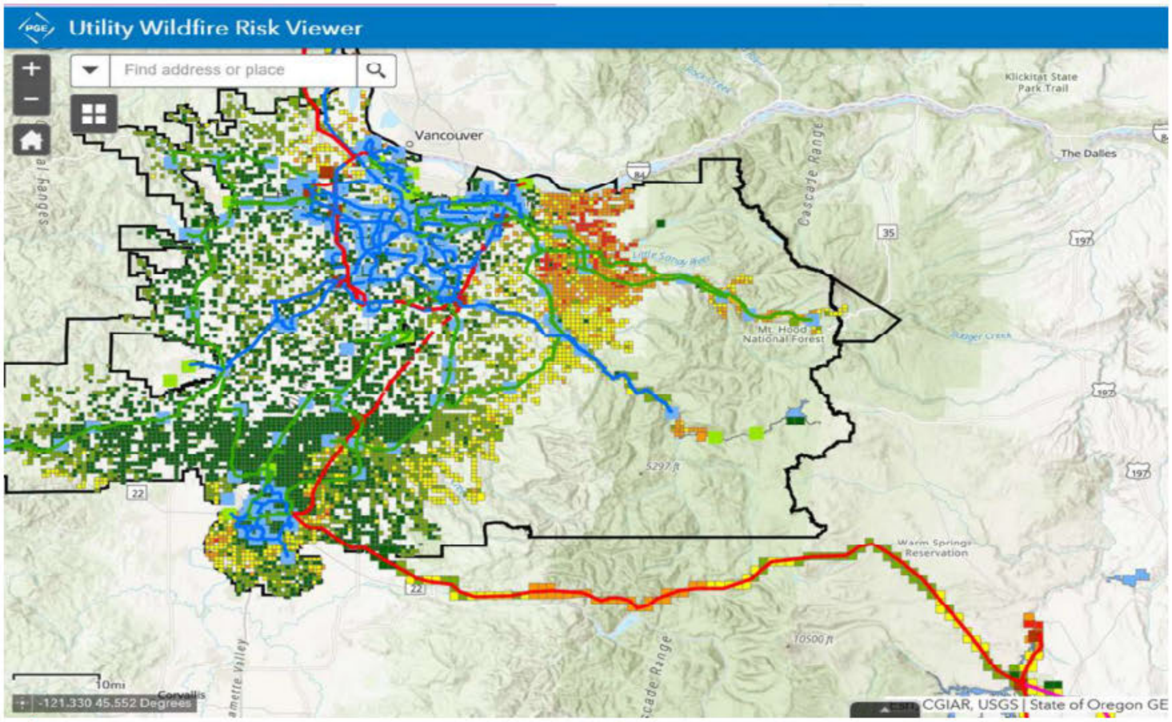


FIGURE 5: AVERAGE ANNUAL UTILITY WILDFIRE RISK FOR ALL T&D STRUCTURES, POLES BY GRID

In sum, this application of the model can help us determine where to focus wildfire mitigation resources to have the most impact on potential wildfire risk.

Modeling Georisk

In 2021 PGE's Baseline Utility Wildfire Risk model was enhanced to evaluate which areas of the PGE service territory should be identified as potential PSPS Zones. The modelers leveraged data from the remote sensing project to quantify the threat of wildfire ignition due to vegetation impingement and weather-caused outages. Modelers predicted the probability of vegetation-caused outages using a statistical model built on historical outage data, characteristics of each distribution circuit, and detailed information about the quantity, density, and types of threats vegetation posed to each geographic sector.

Modelers converted the expected number of outages to the probability of a vegetation-caused wildfire for each protected section. Average annual utility wildfire risk was calculated as it was in the baseline risk model. Lastly, the model considered the fact that utility-caused wildfires are more likely to occur during dry, windy conditions, and weighted the risk by protected section to address the conditions when shutoffs are most likely to be initiated.

This georisk model allows PGE to evaluate wildfire risk at a more granular level to identify the specific areas of the PGE service territory in which PSPS might be warranted.

Prioritized Opportunistic Interventions

In general, when cost of repair is higher than the value of the asset, the asset should be replaced. Once crews are mobilized, there may also be reliability and economic benefits to proactive asset replacement. This application of the model can help PGE assess the cost/benefit of proactive asset replacement during planned maintenance activities on other assets, enhancing reliability and system hardening. This has the added benefit of better protecting utility infrastructure against non-utility-caused wildfires and other events, helping PGE maintain critically important electric service and supporting public safety and firefighting.

Justified Enhanced Inspections

Inspections are most beneficial in cases where wildfire consequence is high, and additional inspections can help ensure equipment is in good condition. PGE's risk assessment model calculates the value of enhanced inspections using data on asset demographics and condition, as well as length of time since the equipment was last inspected. Completing inspections reduces PGE's overall utility wildfire risk, because in combination with targeted maintenance and replacement projects, they allow us to verify that assets are in good condition. This application of the model can also help us answer the question, "Where are inspections most beneficial?" In addition to this work, PGE will annually inspect 100 percent of the assets in its identified PSPS areas.

In addition to work performed by the Strategic Asset Management (SAM) team, all PGE work is evaluated and approved through corporate governance committees informed by an annual enterprise risk assessment that evaluates the likelihood of threats (e.g.: cyberattacks, natural disasters) and their potential impacts (e.g.: financial and reputational outcomes, public and employee safety, environmental impacts). PGE also conducts periodic Hazard Vulnerability Assessment (HVA) and Enterprise Risk Management (ERM) processes to provide broader-scale, enterprise-level assessments of the various risks PGE faces.

7.1(c) Targeted Interventions to Reduce Wildfire Risk

1. Preparedness, Situational/Conditional Awareness, Vegetation Management, System Hardening

As fire season approaches, PGE's WM&R staff and PGE meteorologists review regional National Weather Service forecasts, fire activity briefings, fire potential forecasts, and readings from strategically located PGE weather stations on a daily basis. Based on its experience during the 2020 fire season, in 2021 PGE is deploying additional weather stations to increase situational and conditional awareness.

PGE continues to leverage its SAM utility wildfire risk methodology and Fire Safe Construction Standards to harden the T&D system in the seven PSPS Zones. System hardening activities are designed to accomplish three goals:

- Reduce the risk of wildfire ignition caused by PGE facilities
- Reduce the impacts of a wildfire on PGE's assets
- Protecting utility infrastructure during <u>all</u> potentially-disruptive natural and human-caused disasters (not only utility-caused wildfires), supporting PGE's ability to maintain and quickly restore reliable electrical service to support disaster relief and public safety.

In working towards both of those goals, PGE will safeguard communities in areas threatened by elevated wildfire risk and will also implement reliability improvements for these customers. As outlined in PGE's Fire Safe Construction Standards, the following assets will be evaluated for replacement when warranted under the SAM methodology:

- Identifying wood poles within PGE PSPS areas that should be targeted for replacement with fire-resistant recycled ductile iron poles
- Fuses – selectively replacing existing expulsion fuses with non-expulsion fuses
- Conductor – where warranted, replacing undersized/aging conductor and considering use of tree wire
- Crossarms – selectively replacing wood crossarms with fiberglass arms
- Cutouts – selectively replacing porcelain cutouts with polymer cutouts
- Specific 2021 efforts
    - Install faulted circuit interrupters (FCIs) in the Mt Hood PSPS zone
    - Install Viper reclosers in the Mt Hood and new PSPS zones
    - Install an early fault detection system pilot in the Mt Hood PSPS zone.

Efforts to evaluate and prioritize these system hardening initiatives began in 2020 and will continue into subsequent fiscal years, as PGE's SAM team continues to refine the utility wildfire risk model.

7.1(d) Evaluation of Mitigation Effectiveness

WM&R will track the effectiveness of its wildfire mitigation program through a variety of metrics. As always, evaluating mitigation performance is a relatively straightforward exercise; evaluating mitigation effectiveness is more challenging. At the conclusion of the 2021 wildfire season, PGE will evaluate changes to its wildfire risk profile resulting from Wildfire Mitigation Program activities.

To the greatest extent possible, PGE will track the outcome of its 2021 Wildfire Mitigation Program activities by estimating the amount of wildfire risk PGE has mitigated through achievement of performance measures. Wildfire Mitigation Program stakeholders are working to identify a wildfire risk reduction estimate methodology and will report the outcome of these efforts in the 2022 PGE Wildfire Mitigation Plan.

7.2. Vegetation Management

Even in Oregon, with its legendary rains, summers are getting hotter and dryer, and wildfire seasons are getting longer. Throughout the West Coast, the overall risk of wildfires is increasing. Because vegetation impingement is a leading source of wildfires ignited by the electrical grid, PGE's Vegetation Management organization plays a key role in our wildfire preparedness efforts. PGE manages more than 2.2 million trees within the ROW of 12,000 miles of overhead power lines and has expanded its Vegetation Management program to trim and remove more trees and shrubs that are overgrown, dead, dying or showing growth defects that could impact overhead power lines within the ROW and easement. The strategy includes removal of select trees from the ROW and easements, but is challenging due to conflicting local ordinances and policies.

Traditionally, wildfire vegetation management relationships between regulators and the regulated have been based on a compliance approach, with a heavy emphasis on tree trimming, rather than removal. PGE has evolved its wildfire vegetation management program to include both compliance and risk-based approaches. This is evident in PGE's AWRR program, which emphasizes targeted tree removals. However, many city, county, state and federal regulatory entities continue to follow a compliance paradigm that limits tree removals, an approach that could hamper the full implementation of wildfire risk mitigation efforts. PGE needs the assistance of the regulator community to repeal or change historic rules/ordinances that delay the risk mitigation efforts necessary to reduce the likelihood of vegetation-caused wildfire ignition. PGE will continue to foster these relationships, both internally and externally, to create partnerships that more effectively reduce wildfire risk.

Due to the aggressive expansion of PGE's Vegetation Management work at the core of this Wildfire Mitigation Plan, PGE is taking a phased approach to implementation of our enhanced work in areas identified as high-risk. We want to be very clear that while we are identifying these PSPS areas as high-risk, our current method of mitigating risk in these areas is proactive implementation of a PSPS and system protection settings – it will not be possible to perform enhanced vegetation management and pole inspection work in all of these areas prior to fire season. PGE will be able to complete much of this work, but there are serious constraints to completing all of it prior to wildfire season declaration, and we want to be sure that there is no confusion on this point.

7.2(a) Roles & Responsibilities

Vegetation Management Manager, Vegetation Management	Manages the Vegetation Management AWRR program
	Conducts 100% annual AWRR line patrol for "cycle busters" and P1 trees (hazard/danger).
	Performs annual vegetation inspections of all overhead line mileage that falls within PSPS areas
	Develops vegetation management strategies based upon inspection results
	Performs 100% quality assurance/quality control (QA/QC) of vegetation management inspection and mitigation work completed by crews
	Coordinates vegetation management activities with external stakeholders and agencies (Oregon Department of Forestry, USFS, Oregon Department of Transportation, counties, municipalities)
	Secures vegetation-specific permits and waivers from responsible external agencies
	Coordinates with crews and leadership during extreme fire danger conditions and restrictions to work hours/equipment, Industrial Fire Precaution Levels (IFPL)
	Verifies and performs routine inspection of tooling and equipment requirements for crews during fire season

7.2(b) Overview of PGE Vegetation Management Strategy

PGE's vegetation management strategy is managed by the Vegetation Management division of PGE's Forestry department, with input from the WM&R organization. It has two major components: PGE's Routine Vegetation Management program, and the AWRR program.

Routine Vegetation Management: About 10,000 line-miles of PGE's 12,000-mile overhead network require regular vegetation management inspection; the other 2,000 miles passes over areas with no potentially-hazardous vegetation (such as water). Under PGE's Routine Vegetation Management program, we inspect about one-third of our overhead transmission assets annually; depending on location, all assets are inspected either every two or every three years. Routine inspection timing may change as PGE continually evaluates the effectiveness of our Vegetation Management cycles. Routine inspections are ongoing throughout the year, rather than pre-season only. Routine Vegetation Management inspections identify both P1 and P2 trees.

AWRR Program: Prior to PGE's Start of Fire Season declaration, PGE annually inspects 100 percent of the overhead assets within the seven PSPS Zones for condition and vegetation impingement. PGE implemented the AWRR program to target the most pressing utility wildfire risk factors, including off-ROW and grow-in threats. In addition to P1 and P2 trees, AWRR inspectors look for "cycle busters" (vegetation outside of the five-foot State of Oregon line clearance corridor, including otherwise-healthy trees that could pose a future grow-in/fall-in threat to PGE infrastructure).

Primarily focused on inspection and maintenance activities in the high wildfire risk portions of the PGE service territory, as identified through PGE's PSPS assessment process, PGE's Vegetation Management strategy includes both cyclical, routine inspections and maintenance of the entire PGE transmission system, and AWRR activities driven by PGE's wildfire risk analytics. Specific, year-to-year vegetation management activities are guided by PGE's Risk Assessment Program and extensive program of annual vegetation surveys. The AWRR program includes enhanced trim specifications, increased removal rates of prioritized species, and enhanced vegetation control techniques, discussed in more detail below.

7.2(c) Routine Inspection & Maintenance Strategies - Vegetation Management

PGE contractors, supervised by the Vegetation Management organization, annually inspect about one-third of PGE's 12,000 miles of overhead assets through the Routine Maintenance Program. PGE coordinates its vegetation management activities closely with external stakeholders, including the US Forest Service (USFS), Oregon Department of Forestry (ODF) and private landowners, to maximize the reach and effectiveness of its annual vegetation management program.

PGE conducts its routine vegetation management activities throughout the year (rather than pre-season only, as is the case with the AWRR program) and throughout the PGE overhead system (rather than PSPS areas only) to identify and mitigate both P1 and P2 trees. P1 trees are mitigated pre-fire season; P2 trees are marked for removal/remediation throughout the year. PGE trims all marked trees to our specifications during the two- to three-year Routine Maintenance cycle, ensuring that the minimum clearances necessary for compliance with state standards and Division 24 are maintained throughout PGE's overhead system.

PGE subjects its vegetation management activities to a rigorous QA/QC process. Verification that all vegetation management tasks have been completed to specification is tracked through PGE's vegetation management technology platform, ArcGIS Collector. In addition, all work is field-validated by PGE managers, who work closely with the crews to confirm completion; crews also document completion through time- and date-stamped photos, in some cases, of individual trees.

7.2(d) Advanced Wildfire Risk Reduction (AWRR) Vegetation Management Program for High Risk Areas:

Oregon Administrative Rules (OAR) Division 24 Safety Standards outline the minimum vegetation clearances required throughout the State of Oregon, at least 5 feet from vegetation to conductors energized from 600 to 50,000 volts. This section of the OAR also establishes common definitions of "hazard" and "climbable" trees. These requirements are in place as a public safety measure. Division 24 Safety Standards and the National Electrical Safety Code (NESC) provide the foundation of PGE's overhead maintenance program. While Division 24 standards guide PGE's routine overhead maintenance programs, Division 24 does not specifically address mitigation strategies.

Division 24 goes beyond mandatory minimum clearances to mandate other considerations in determining the extent of work required to maintain safety and reliability – sag and sway under wind and ice loading, configuration of construction, growth habit, strength and health of vegetation adjacent to the conductor – allowing PGE to go beyond mandatory minimum clearances to execute our Vegetation Management strategy. PGE routinely uses this guidance to conduct vegetation management activities beyond the ROW; property owner consent is not required if PGE deems the work necessary. PGE's annual vegetation management workflow is prioritized based on results from the Phase 2 risk assessment model, concentrating on the priority feeders within each PSPS Zone.

PGE's AWRR program has multiple components, providing annually occurring inspections/work templates of all designated overhead (OH) line mileage, as well as ongoing cyclical work aimed at providing more robust hardening of specific segments or spans of designated overhead line.

PGE Vegetation Management follows ORS 758.280-758.286 to provide much of the operational framework for AWRR-related activities, as most of this work is occurring outside of designated PGE rights-of-way (ROW), utility easements and annual maintenance schedules.

The AWRR program is managed in-house through PGE's Vegetation Management department. Internal staff manages 100 percent of the AWRR program, from work schedule to QA/QC of completed work. Vegetation Management staff also manages the ongoing work being performed through consistent and robust presence in the field with the crews completing specified work.

AWRR activities are independent of PGE's annual vegetation management cycle; its vegetation prescriptions exceed our internal maintenance trimming specifications and the minimum clearances outlined in OAR Division 24. Tree removal practices associated with AWRR are applicable to any tree within striking distance, regardless of current tree health conditions. AWRR crews utilize equipment and tooling that has traditionally been non-standard within PGE Vegetation Management such as the 105-foot lift, Jaraff all-terrain tree trimmer, and the Slashbuster/Forestry Mower heavy-duty brush cutter. AWRR operations fall outside of PGE's routine maintenance and trimming operations as the scope, operational practices, inspection schedule and cadence are all on escalated cycles.

The AWRR program differs from but compliments PGE's Routine Maintenance Program by focusing on results from PGE's Phase 2 risk assessment program, as expressed through the identification of the seven PGE PSPS Zones. PGE used a broad spectrum of risk factors to identify its PSPS Zones, including asset classification, age, configuration and protection strategies, weather modeling, forestation, fueling, and external stakeholders' risk assessment.

FIGURE 6: SLASHBUSTER HEAVY-DUTY FORESTRY MOWER

FIGURE 7: FORESTRY BUCKET AND TREE-TRIMMING CREW ON AWRR DEPLOYMENT

7.2(e) Inspection & Maintenance Frequencies- Vegetation Management

PGE's vegetation management program includes both annual, routine vegetation inspections of the entire PGE system, and intensive pre-wildfire season vegetation inspection and maintenance in PSPS zones through the AWRR Program.

Note that specific annual work plans may change in-season in response to inspection findings.

Annual: Prior to Fire Season

Vegetation Inspection

Off-cycle inspections of vegetation ensure ongoing vegetation clearance compliance and identification of any vegetation that has become a risk since the prior inspections. These inspections occur annually, outside of PGE's standard 2-3-year vegetation maintenance cycle.

Hotspot Tree Trimming

As PGE Vegetation Management inspectors identify "cycle-buster" vegetation, off-cycle tree crews are dispatched to trim the vegetation back to specification.

- Trees and other vegetation will be removed should the vegetation pose grow-in/fall-in risk, as identified by PGE Vegetation Management employees performing the off-cycle annual inspection.

Annual: Cyclical

(a) Enhanced Vegetation Management (EVM) Techniques

PGE Vegetation Management often prescribes vegetation control techniques for AWRR projects that exceed standard line-clearance specifications. These prescriptions include greater side-clearance, overhang removal, selective removal of tree parts, and whole tree removal.

- A significant majority of the EVM techniques are being executed outside of ROW or utility easement, through agreements with the USFS and individual property owners.
- Mowing / herbicide / tree growth regulator
- PGE has increased the use of ROW-specific mowers, aimed at eliminating small-diameter trees within ROW[3]. These efforts reduce ground fuels, eliminate small-diameter trees that could pose risk to PGE infrastructure, and significantly improve crew access.
- Improving firefighter and maintenance access is a significant secondary benefit of this effort, reducing response time to outages and emergencies for PGE, USFS, and other emergency management agencies.

[3] Because lightning is a more common source of ignition resulting in destructive wildfires than utility infrastructure, PGE must also continue to harden its system against other types of fires caused by nature. Many of PGE's system hardening measures, such as replacement of wood poles with ductile iron poles and removal of small-diameter trees within the ROW, provide this double benefit.

- PGE has increased the use of ROW-specific herbicides and tree growth regulator to promote desirable species and reduce wildfire risk associated with invasive species. PGE will comply with all ORS 758.280-758.286 landowner notification requirements prior to deployment of any chemically-based vegetation control measures.

7.3. Asset Management, Inspections & Capital Investment

Inspections of PGE transmission and distribution assets in high wildfire risk areas are conducted through PGE's Asset Management & Inspections program. Program managers also implement strategic replacement projects directed by this annual Wildfire Mitigation Plan, to reduce wildfire ignition risk along PGE transmission and distribution pathways. PGE Transmission Patrolmen also inspect all transmission circuits in its Central Oregon High Wildfire Risk area.

PGE asset managers across multiple departments play a critical role in wildfire preparedness and response throughout the year, including the specific actions referenced in the Roles & Responsibilities section, below.

The Utility Asset Management group (Distribution) and Grid Maintenance Engineering (Transmission)'s annual inspection cycle for PGE-identified PSPS areas combine with PGE's annual Facilities Inspection and Treatment to the National Electrical Safety Code (FITNES) inspection cycle to annually survey 100 percent of assets within the PGE-identified PSPS areas. PGE performs additional inspections on its transmission assets.

PGE's Inspections, Maintenance and Capital Investment programs are foundational to PGE's wildfire preparedness and mitigation efforts and are especially critical in light of the ever-increasing wildfire danger to the Pacific Northwest. The goal of these programs is to maintain and enhance both the reliability and the wildfire resistance of PGE's transmission and distribution systems through vigilant maintenance, asset replacement and upgrades informed by research and development and industry best practices, and strategic capital investment in situational awareness and system hardening technologies.

7.3(a) Roles & Responsibilities

Utility Asset Management	Conducts annual inspection of PGE distribution located in PGE-identified PSPS zones
Manager, Utility Asset Management	If conditions are identified via inspection, UAM's FITNES program routes the repair tasks to Vegetation Management, the Project Management Office (PMO), Utility Engineering and Design or pole attaching entities for repair
	Participates in seasonal, internal meetings, exercises and stand-ups with personnel on fire season conditions
	Requires contractor job safety briefings to include wildfire risks during wildfire season
	Completes training on PPE and fire equipment use with Wildfire Program Coordinator, in accordance with annual compliance training

	One of several organizations that ensures that PGE vehicles for field employees are equipped with correct fire suppression tools and equipment.
	FITNES program personnel assign upgrades, repairs and maintenance tasks identified during inspections to appropriate entity (Vegetation Management, Generation, Transmission & Distribution (GT&D) Project Management Office, pole attaching entities) for timely resolution

Generation, Transmission & Distribution Project Management Office	Provides engineering and project-related support, technical project and construction management and maintenance services for all asset classes, as well as planning and design of new and/or upgrade installation projects as required by PGE customers
Manager, Generation, Transmission & Distribution Project Management Office	Manages construction projects through engineering, procurement, construction and commissioning
	Serves as program project manager (PPM) with responsibility for meeting project goals for safety, budget, schedule, scope, resources, compliance and quality, and for ensuring that projects deliver quality and value to the customer while meeting environmental, regulatory and community requirements

Utility Standards Engineering - Design Standards & Construction	Develops and documents fire construction standards to aid designers and line crews in the design and construction of PGE T&D assets as they relate to work within pre-identified PSPS areas
Manager, Utility Standards Engineering	Engages with other electric utilities and industry groups to identify industry best practices for wildfire mitigation of the electric system.
	Discusses fire hardening efforts with other electric utilities to identify industry best practices
	Leverages relationships with vendors and industry institutions to evaluate and introduce new technology into PGE's system
	Delivers periodic standards updates through a bi-monthly standards newsletter and training/outreach to internal departments on updated and evolving standards
	Leads the evaluation of failed T&D system components and provides solutions to remedy identified issues
	Works closely with vendors and industry institutions, such as the Institute of Electrical and Electronics Engineers (IEEE) and Electric Power Research Institute (EPRI) to identify and introduce new wildfire detection and suppression technologies to PGE.

Distribution Engineering - Distribution Operations Engineering Manager(s), Distribution Operations Engineering	Coordinates with System Protection Engineering and Distribution Automation Engineering annually to review system protection settings for line devices to ensure proper coordination and operation in and out of declared wildfire seasons
	Coordinates seasonal changes of system protection devices to reflect wildfire risk
	Reviews fault events on distribution circuits located within PSPS zones to verify that system protection is functioning properly
	Reviews capital work orders prior to job approval, and provides recommendations for designs to best fit wildfire mitigation strategies
	Works with Standards, Distribution Automation, and Wildfire Analytics R&D to adopt new technologies aimed at enhancing system operation, event detection and location (e.g. communicating fault indicators, high impedance fault detection, non-expulsion fusing, etc.).
	Reviews devices associated with PSPS isolation locations and provides recommendations for automated device installations.

Grid Maintenance	Defines requirements and coordinates annual inspection of transmission circuits in its Central Oregon High Wildfire Risk area
	If conditions are identified via inspection, designs and/or coordinates the repair.
	Participates in seasonal, internal meetings, exercises and stand-ups with personnel on fire season conditions
	Completes training on PPE and fire equipment use with Wildfire Program Coordinator, in accordance with annual compliance training

Operations	Partners with internal stakeholders to develop and document work practices to aid in the fire hardening of PGE's T&D system through improved construction practices

7.3(b) Equipment & Design Standards

This section focuses on the standards for designing and building overhead distribution and transmission lines in PSPS zones. The Design Construction and Standards groups have responsibility for most of the activities in this track.

PGE's Utility Standards Engineering organization will conduct an annual review of its T&D Standards library to document and implement any wildfire-related changes identified during the post-season After-Action Review (AAR) process. In 2021, this process resulted in changes to the PGE equipment and design

Standards governing the use of ductile iron poles, wood pole fire protection wrap, and tree wire, among other changes.

PGE's Fire Safe Construction Standard (updated for 2021) describes the current PGE-standard methods and materials for poles, conductor, crossarms, insulators and cutouts in PSPS zones. In addition, PGE's Weather Monitoring Station Installation, Clearance and Maintenance Requirements Standard provides guidance on the installation and maintenance of weather stations mounted on wood and ductile iron transmission and distribution poles.

7.3(c) Routine Inspections & Maintenance

PGE operates extensive programs of both inspections and maintenance, distinguishing between periodic, time-based inspections and preventative maintenance to meet compliance requirements (which would occur independent of fire risk), and emerging issues/deficiencies that are identified throughout the year and require timely PGE intervention. PGE's Distribution Line Operations organization has developed a Transmission Line Inspection Methodology document to guide the routine inspection process.

Routine patrols/inspections may also discover defects or deficiencies that must be corrected to prevent incipient failures -- missing or damaged animal guards/avian protection devices, for example, or loose hardware, missing grounds, etc.

During a typical calendar year, PGE accomplishes an array of routine inspection and maintenance activities:

PGE FITNES OH Inspection Program and Safety Patrols: PGE's longstanding FITNES program is designed to meet the requirements of OAR 860-024-0011(1)(b). FITNES results in the detailed inspection of 10 percent of PGE's poles and related overhead facilities each year, 100 percent of poles and facilities every 10 years. FITNES inspectors use a detailed visual inspection of structure and support systems (poles, crossarms, insulators, guys, anchors, etc.), grounding, conductor clearances and conditions, etc., as well as hammer sounding or actual measurement of remaining pole shell from grade to six feet above grade. Poles older than five years also receive remedial internal treatment. The FITNES inspection is performed by contract inspection personnel who annually walk PGE's overhead electric supply lines.

PGE performs an annual safety patrol of 50% of the entire PGE system to meet requirements of OAR 860-024-0011(2)(c). The safety patrol is performed by PGE inspectors who drive by the overhead supply lines and related accessible facilities and inspect for conditions that may pose a hazard to the public. These conditions include, but are not limited to, broken poles, structures with extreme external decay, broken or severely split cross arms, broken-down guys, vegetation such as ivy growing more than halfway up poles, low conductors, conductors off insulator, broken insulators, broken conduits, and anchors pulled out of ground.

Enhanced FITNES Wildfire Mitigation Inspections for High Fire Risk Areas: PGE's Wildfire Mitigation Inspections began in 2019 and now cover the entire extent of the Phase 1 Risk Areas identified by PGE's Risk Assessment program on an annual basis (about 4,200 structures in all). PGE will inspect the circuits and facilities in all seven identified PSPS zones during 2021. This effort will leverage the ongoing FITNES program cycle, which inspects 10 percent of the PGE system annually, with PGE's Wildfire Mitigation inspection program to ensure that all structures in the PSPS areas in PGE's service territory are inspected annually.

Inspection Process

PGE's Wildfire Mitigation Inspections are detailed and involve a walk-through approach as opposed to a patrol. PGE personnel visually inspect structures, lines, and equipment from the ground using binoculars and/or a spotting scope mounted on a tripod.

In addition, transmission patrolmen from PGE's Grid Maintenance organization patrol and inspect the transmission lines in the Central Oregon High Wildfire Risk area to identify potential vegetation management, structural or maintenance issues.

Once wildfire season has been declared and PGE's wildfire system protection measures are operational, if a feeder breaker opens, recloses, and holds, all subsequent reclosing on the feeder breaker is blocked until PGE inspection crews can be mobilized to patrol and inspect the entire feeder and identify the cause of the original fault. If a feeder breaker or recloser opens, an inspection crew must inspect the circuit "downstream" of the open device before re-energizing. Depending on the source, PGE's line operations or vegetation management organizations may be responsible for clearing the fault.

7.3(d) Asset Lifecycles & Replacement Criteria

1. Standard lifecycle

PGE's Strategic Asset Management (SAM) program uses a data-driven, customer-focused approach to quantify the costs and benefits of asset replacement, the basis for PGE's standard lifecycle decision-making. This approach provides PGE an analytical basis for identifying, evaluating, & prioritizing system investments. SAM's risk-based approach to asset management allows PGE to understand asset risk or criticality relative to other assets, aggregate risk in the system based on a program/project scope, and quantitatively define benefits.

SAM's Wildfire Risk Model calculates risk based on all wildfire ignition sources at a given structure (i.e., the structure and attachments, vegetation, and animals) as well as the expected consequences of a wildfire at that location. For each structure or pole, it evaluates the following data:

- **Probability**: The model calculates the annual probability that any of PGE's equipment at a given location will be the cause of a wildfire, including effects from vegetation and animals. Probability is estimated by spreading the expected annual system-wide number of utility-caused fires across all equipment, according to how likely each type of component is to spark a fire, weighted by age and condition.
- **Consequence** (net value change): The consequence cost of a wildfire is an estimate of the expected damage that would result from a large (e.g., >400 hectare) utility-caused wildfire at a given location. Costs are evaluated using a standardized point scale (net value change; NVC), developed for use by the California utilities. These scores are then converted to equivalent dollars by calibrating them against estimated actual dollar costs for known fires. Consequences are based on many fire simulations across the full range of weather and fuel conditions for a given location.
- **Risk**: Risk is the expected cost of wildfires caused by PGE equipment at a given location, the product of probability and consequence. Because both factors are annual averages, so, too, is risk. Real-time conditions that affect probability or consequence (or both) have a proportional effect on risk.

Asset lifecycle decisions are based on asset health, generally assessed using PGE's annual inspection data, component age and failure trends for a given distribution system component or class. The following table illustrates the average service life of some classes of key distribution assets:

Item	Depreciation Group (FERC Acct)	Average Service Life (yrs)
Distribution Poles & Crossarms	364 – Poles, Towers and Fixtures	48
Overhead conductor - Distribution Trip savers and other reclosers Switches Fuses	365 - Overhead Conductors and Devices	50
Distribution Transformers	368 – Line Transformers	50

2. *Wildfire Correction Criteria*

PGE categorizes wildfire corrections as follows:

- A violation that poses an imminent danger to life or property will be repaired, disconnected, or isolated by the operator immediately after discovery
- A violation that poses a hazard will be corrected as soon as practicable but no later than 30 days after discovery
- All other violations are corrected in accordance with OAR 860-028-0012.

Notwithstanding these categorizations, should the contractor identify a condition that poses an imminent danger to life or property, the contractor shall immediately notify PGE Repair Dispatch and stand by onsite until PGE crews respond.

7.3(e) Capital Programs

In 2021, PGE's T&D PMO is managing a portfolio of wildfire-related capital projects, including:

- Installation of intelligent faulted circuit interrupters
- An early fault detection system
- Advanced reclosers
- Substation protection upgrades
- Replacement of PGE assets damaged during the 2020 fire season, to help PGE maintain reliable electric service to support public safety and emergency response activities[4]
- New weather stations in PSPS areas.
- Pole replacements and new pole installations associated with inspection findings

[4] Because lightning is a more common source of ignition resulting in destructive wildfires than utility infrastructure, PGE must also continue to harden its system against other types of fires caused by nature. Many of PGE's system hardening measures, such as replacement of wood poles with ductile iron poles and removal of small-diameter trees within the ROW, provide this double benefit.

- Replacement of avian protection devices
- Replacement of end-of-life PGE assets in PSPS areas.

PGE's 2021 capital budget includes funding for the following wildfire-related activities:

Preparedness/Situational & Conditional Awareness

- Weather Stations: PGE is installing additional weather stations in 2021 with the expansion of the number of PSPS zones. These new weather stations will provide more granular weather information to help inform situational awareness during extreme events. Additionally, PGE has purchased four mobile weather stations to be deployed as needed in 2021.

Mitigation

- Wood Pole Replacements: whenever feasible, PGE will replace primary (with ductile iron poles) wood poles located in PSPS zones areas and reported to be in bad order (in need of replacement or repair) during their annual inspection Note secondary wood poles that are identified to be replaced will be replaced with wood.
- Crossarms: PGE will replace wood crossarms with fiberglass arms if inspected and determined to be end of life/bad order.
- Cutouts: PGE will replace porcelain cutouts with polymer cutouts if the cutout is inspected and determined to be damaged.
- Fuses: PGE will install wildfire-safe fuses when replacing equipment currently protected by expulsion fuses.

Efforts Specific to 2021

- Install Faulted Circuit Indicators: PGE is installing intelligent faulted circuit indicators in the Mt. Hood corridor to provide real-time system data to help identify and isolate feeder disturbances.
- Install Viper Reclosers: PGE plans to install Viper reclosers (electronically-controlled vacuum fault interrupters) in up to 14 locations in 2021.
- Early Fault Detection Pilot: PGE will install early fault detection equipment at multiple locations in the Mt. Hood Corridor PSPS zone to detect emerging electrical asset failure remotely, before adverse outcomes occur.
- Inspection Correction -- Remove Tree Attachments: PGE is continuing to scope the number of poles that must be installed in 2021 to correct this issue.
- Recovery: Capital projects to replace structures damaged during the 2020 wildfire season at PGE's Redmond-Round Butte and Pelton-Round Butte projects.
- UAM Tape & Shape (T&S): Part of the annual FITNES process to correct conditions discovered during their annual inspections – the large volume of work that doesn't require Design or Engineering assistance. T&S is a recurring expense that PGE budgets for each year. In 2020, FITNES inspections identified approximately 2,700 conditions that needed to be addressed, 2,000+ through the annual T&S process.

It is important to note that many of the PGE projects related to wildfire preparedness, such as system hardening measures, emergency operations preparedness, and risk assessment planning for all hazards also have benefits under a wide range of disaster scenarios. This double benefit outweighs any potential concerns regarding ratepayer impacts and the appropriate scale of PGE's wildfire mitigation expenditures.

(a) Wood Pole Replacement Strategy in High Wildfire Risk Areas

- Whenever feasible, PGE will construct new or replacement distribution and transmission structures using a non-wood alternative in PSPS zones. Ductile iron is the current standard material to be used for distribution poles, and ductile iron or steel has been approved for transmission structures. Both of these pole materials are impervious to rot, insects, and woodpeckers, and are highly fire resistant. These non-wood alternative poles are manufactured to meet minimum tip load and moment equivalents of wood poles under NESC Grade B construction standards. PGE began phasing in the use of wood pole alternatives in 2020. Poles will be replaced as needed, based on PGE's Detailed Inspection cycle and targeted annual Wildfire Inspection Cycle**.** Note secondary wood poles that are identified to be replaced will be replaced with wood.

Additional Protection for Wood Poles: PGE is continuing to evaluate fire retardant products to determine where they will most effectively provide additional protection to wood poles from ignition due to fast-moving surface fires. In 2021, PGE funded a pilot program to test fire retardant mesh at the base of wood poles in high-risk areas. Pilot program results will be evaluated following the 2021 wildfire season.

Transmission Bonding and Grounding: In addition to wood pole replacement efforts, PGE has found that, under certain line loading and atmospheric conditions, bonding and grounding of 230 kV (and above) wood structures can cause pole fires when compromised though damage or faulty installation. PGE reliability technicians have now surveyed the current state of bonding and grounding on all wood 230 kV structures in the PGE transmission system, and have now completed all required grounding and bonding-related repairs.

7.4. Operating Protocols

At the start of each wildfire season, PGE identifies a date and time when the primary wildfire season activities will begin. Declaring the start of PGE wildfire season initiates work needed to shift work practices, grid operating procedures and communication processes to wildfire season mode for a specific region or all areas where the company operates and has facilities.

Once approved, the declaration of wildfire season:

- Initiates changes to how the company operates the PGE network, initiating wildfire-season-specific settings on parts of the grid, including disabling reclosing/testing capabilities, where applicable
- Initiates wildfire season operational work practices in the field
- Increases monitoring and communication requirements and use of other technologies for near real-time wildfire-related situational awareness (e.g., GIS Alerts and Kestrel field weather monitor readings).

Although the ODF officially declares the start and end of wildfire season each year in Oregon, PGE makes an independent determination of the start and end of PGE Wildfire Season, for the following reasons:

- PGE prefers to be in wildfire operations prior to the official agency declaration for PGE's area of operation – we make changes to system operations once PGE Wildfire Season has been declared, and want those changes to be in place prior to any agency action
- PGE wants to declare the end of Wildfire Season Operations after agencies declare the official end to wildfire season
- This conservative approach exceeds regulatory requirements and is accomplished through close communication and strong relationships with the relevant external agencies.

PGE also separately declares the start and end of wildfire season east and west of Cascade Crest; PGE believes that this approach is more effective than treating every part of our service territory the same, regardless of conditions on the ground. In 2021, this resulted in PGE declaring the start of wildfire season east of Cascade Crest on May 14.

Once it declares the start of wildfire season, PGE will initiate wildfire programmatic elements until the end of wildfire season is declared, or if conditions change and wildfire season work is required during the off-season.

PGE's System Control Center (SCC) Fire Risk Mitigation procedure provides operational guidance to PGE system operators to reduce the risk of a wildfire starting as the result of a fault or operator action on PGE's T&D system. This is accomplished by limiting the use of line testing and automatic reclosers during wildfire season and outside wildfire season when wildfire danger is elevated. This procedure also allows PGE to initiate PSPS operations under specific high-risk conditions. This procedure remains in effect during a declared PGE wildfire season or when a Red Flag Warning or Fire Weather Watch is declared by PGE outside of the PGE Wildfire Season.

Situational and conditional awareness of wildfire risk increases life and property safety and grid resilience in the PGE service territory. Steps to achieve this include:

- Implementation of SCC Fire Risk Mitigation Procedures that include actions to reduce the risk of fire ignition due to system settings
- Coordination with PGE's WM&R department for the distribution of daily fire weather forecasts, and weekly/seasonal outlooks to SCC staff
- Monitoring grid status and adjusting system settings based on forecasted, current or unexpected changes in atmospheric conditions (as outlined in the SCC Fire Risk Mitigation Procedure) to minimize wildfire risk in the PGE service area.

PGE wildfire mitigation operations include the following specific actions. Before the start of PGE-declared wildfire season PGE system operators will manually block all non-remote controlled (non-SCADA) distribution reclosing devices in its PSPS areas from automatically test-energizing circuits following temporary faults, such as momentary tree branch contacts and lightning strikes with no damage. This reduces the chances that PGE equipment could start a wildfire by automatically test-energizing circuits following temporary faults or permanent faults (e.g.: uprooted tree with wire down).

Once PGE has declared the start of wildfire season (outside of Red Flag Warning status), PGE system operators will reactively block automatic reclosing on any SCADA-controlled device in its PSPS areas after it automatically recloses, and immediately request a patrol of the downstream circuit. The purpose of this action is to reduce the chances that PGE equipment could start a wildfire by automatically test-energizing the circuit following a fault. Patrolling the circuit, even though it is energized with no customer outage, may identify an issue that could reoccur.

During a Red Flag Warning, PGE system operators will proactively block automatic reclosing on every SCADA-controlled device in PGE's PSPS zones. This action reduces the chances that PGE equipment could start a wildfire by automatically test-energizing circuits following temporary or permanent faults.

Protection and Control Devices: PGE engineers annually review and update settings for protection and control devices in PGE-identified PSPS areas to improve utility-caused wildfire prevention. In 2021, PGE will implement circuit breaker and recloser protections to minimize fault energy and effectively reduce the risk of ignition during wildfire season. In addition, PGE engineers annually review and update settings for protection and control devices in PSPS zones to improve utility-caused wildfire prevention.

All of the 13 kV feeders servicing PGE's 2021 PSPS areas (with SEL relays and SCADA), as well as the Pelton and Round Butte transmission lines, can now be set to operate in a specialized wildfire protective mode. Most can now be set to one of three modes: Normal, Wildfire or Red Flag. In Normal mode, the feeder will have two shots of reclosing and instantaneous -- no deliberate time delay to trip when a fault is detected by the relay -- (if enabled). In Wildfire mode the feeder will have one shot of reclosing and trip on definite time instantaneous (a programmed delay before the relay trips). In Red Flag mode the feeder trips on definite time instantaneous and reclosing is blocked. PGE system operators can select these modes via SCADA. Normal and Wildfire modes can also be selected via pushbutton on the front of the relay (SEL-751/SEL-751A relays only.) Pelton has an additional pushbutton for Red Flag mode. This capability helps prevent wildfire ignition if the cause of the original fault (e.g.: a tree branch) is still in contact with the circuit.

13 kV feeders, without SEL relays, will rely on intelligent reclosers, installed near the beginning of the feeder to provide the necessary protection settings modes for Normal, Wildfire and Red Flag designations.

Electronic reclosers servicing PGE's 2021 PSPS areas can now be set to operate in a specialized wildfire protective mode. Like the 13kV feeders, these reclosers can also be set to operate in Normal, Wildfire or Red Flag modes. In Normal mode the reclosers have three shots of reclosing typically operating on two fast curves and two slow curves. In Wildfire mode the recloser will have one shot of reclosing and operate on definite time instantaneous. In Red Flag mode the recloser operates on definite time instantaneous and reclosing is blocked. PGE system operators can select these modes via SCADA; Wildfire mode is selected by putting the recloser in Alternate settings and Red Flag mode is selected by blocking reclosing while in Wildfire mode. This capability helps prevent wildfire ignition if the cause of the original fault (e.g.: a tree branch) is still in contact with the circuit.

Hydraulic reclosers and Trip Savers physically have their handles pulled down at the beginning of wildfire season. This places the devices into one-shot (no reclosing) on their fast curve and they are kept in this protection mode for the duration of wildfire season.

PGE has also implemented additional wildfire-related operational changes. For example, if a feeder breaker opens, recloses, and holds, the system operator can now block all subsequent reclosing on the feeder breaker until line crews can patrol the entire feeder to clear whatever caused the original fault. Subsequently, if a recloser opens, line crews will patrol the circuit downstream of the recloser, prior to closing the recloser back in.

It is important to coordinate protection with the changes during wildfire season. PGE is opportunistically replacing expulsion fuses with non-expulsion Energy-Limiting fuses (ELF), and overhead expulsion tap line fuses with CMU mountings with E-style fuses. Additional protection actions will be coordinated as PGE's system protection capabilities change over time.

7.4(a) Roles & Responsibilities

Utility Operations Vice President, Utility Operations	Declaring PGE Wildfire Season
	Rescinding PGE Wildfire Season
	Authorizing the execution of a PSPS
	Authorizing the rescission of a PSPS

Business Continuity & Emergency Management	Ensuring that applied incident management methodologies are consistent and interoperable with public agencies and other private organizations, using national standards as a baseline.
	Coordinating with county, city and energy partner emergency management resources on incident activities within the T&D footprint and where PGE Generation and Parks resources are located.

Geographic Information Systems	Helps delineate and visualize the PSPS circuit
	Provides site suitability analysis to support location of new weather stations
	Builds and supports a variety of wildfire-specific inspection apps (pre- and post-wildfire season)
	Builds and maintains email and text notifications triggered by confirmed fire starts, a wildfire perimeter, NWS Red Flag Warning, or VIIRS hotspot identified within 5 miles of a PGE facility (circuit, substation, comm tower, etc.)
	Maintains Wildfire Situational Awareness and Fire Weather Zone Forecast maps on ArcGIS Online (AGOL)
	Creates and supports public-facing PSPS map
	Keeps Human Resources (HR) informed of employee location relative to evacuations zones and PSPS zones during events
	Fulfills event-specific data and map requests

Wildfire Operations Program	Maintaining relationships with agency stakeholders (federal, state and local government) to improve the effectiveness of wildfire planning, prevention, and mitigation efforts by increasing situational awareness and mitigating communication barriers between stakeholder groups. Coordinating access for long-term recovery efforts

Management (WOPM)	Strategizing and pre-planning effective, mutually beneficial, coordinated responses to prevent incidents, save lives and facilitate the rapid recovery of essential service coordinate fire response
	Improving the continuity of emergency services during gray- and blue-sky events
	Improving understanding of agency vulnerabilities and values-at-risk (economic, social, and ecological resources that could be damaged because of a wildfire)
	Participating in after-action reviews (AARs), training and exercises
	Increasing agency awareness and first responder safety when working around PGE assets
	Increasing agency awareness about the work PGE is doing around resilience and emergency preparedness
	Educating agency stakeholders on PGE's risk management activities and potential consequences to critical infrastructure from wildfires
	Collaborating and pre-planning the evacuation of PGE facilities, including the parks PGE operates
	Conducting post-season review workshops with agency leaders to inform and improve future fire season operations
	Establishing training programs and coordinating annual fire season training for PGE employees and those acting on behalf of the company
	Improving guidance on operational activities related to critical infrastructure security and resilience, both in steady state and during PSPS or incident response
	In coordination with BCEM, facilitating a post-season year-end review AAR and applying programmatic changes based on lessons learned; coordinating after-action review with BCEM and changes to the program based on AAR/lessons learned
	In coordination with BCEM, facilitating post-incident AARs when requested by Incident Commanders and/or Executive Leadership, and communicating lessons learned to internal/external stakeholders
	Promoting learning and adaptation during and after exercises and incidents
	Participating in agency-facilitated field, virtual or blended exercises, trainings, and meetings, as requested
	Facilitating PGE-led virtual or blended exercises and training with internal and external stakeholders
	Participating in wildfire preparedness meetings with County emergency managers
	Responding to new and emerging wildfire incidents and acting as PGE's liaison and conduit of information and intelligence back to the Corporate Incident Management Team (CIMT)
	Coordinating with the Northwest Interagency Coordination Center (NWCC) and Energy Emergency Management Team (EEMT) members to ensure that annual updates to communication processes with interagency fire dispatch center procedures are completed
	Producing seasonal, monthly, weekly and daily fire weather outlooks and national and regional fire season forecasts

	Coordinating processes that provide daily, real-time or near real-time dissemination of fire season forecast changes, watches, warnings and hazards
	Providing input and coordinating processes and procedures for declaring the start and end of PGE fire season
	Maintaining communication and coordination with internal and external stakeholders' emergency management resources for situational awareness throughout fire season
	Managing Field Observer operations (FOBS) for PSPS events, including training, activation, and organizing, tracking, and analyzing real-time field observations and data
	Managing Community Resource Center operations (CRC) for PSPS events, including pre-planning engagement with community leaders, agencies and external stakeholders, CRC PGE staff training, logistics, coordination, and management
	Maintaining awareness of emerging situations which could warrant an emergency response, facilitating the mitigation of potential business interruptions, and responding to events impacting the continuation and survival of business services and operations
	Completing fire inspections, hazardous fuels evaluations and investigations
	Coordinating and communicating with industry peers to share best practices and lessons learned to benchmark PGE's Wildfire Operations Program Management

Wildfire Analytics Research and Development (WARD)	Evaluation of risk in PSPS and other high potential fire areas
	Supporting Utility Operations with data analytics to effectively execute and manage PSPS events
	Supporting all internal and external partners with wildfire modeling expertise to facilitate communication and decision-making
	Development of risk mitigation strategies to reduce the threat of wildfire to customers and PGE facilities
	Informing construction and operating standards to effectively manage wildfire and PSPS risk
	Evaluating and implementing new technologies to reduce the likelihood of ignition from PGE equipment
	Driving wildfire strategic objectives into other business plans and goals

PGE Meteorologist	Supporting the development of risk assessment models and applications, focusing on the mitigation of asset failure due to weather, fires and climate impacts
	Working with WM&R team members to stand up wildfire-related procedures and processes

	Analyzing historical weather, fire, and energy production data and delivering reports to a variety of stakeholders
	Developing relationships and key partnerships with meteorological, wildfire, energy, and other external organizations to align and continuously improve in-house weather, climate, and risk assessment models
	Developing and maintaining a high-resolution Weather Research & Forecasting (WRF) model that can be used for a variety of purposes, such as wind/solar generation forecasting, highly granular forecasting to assist storm preparedness and restoration, and longer-term fire and hazard assessments
	Interpreting meteorological data and forecasts and communicating the forecasts/impacts to end-users
	Providing daily weather reports to operations with focus on fire weather (regional and nationwide) and regional storms/severe weather
	Producing granular short-term forecasts during storms and high fire danger periods to multiple groups
	Designing wildfire training modules for a wide variety of PGE employees
	Coordinating with external agencies (such as NWS) to strengthen PGE's resiliency during fire/severe weather
	Providing data science to support situational awareness, including but not limited to high resolution WRF/ensemble modeling, visualization of model data, analysis of historical weather observations, etc.

Grid Operations Director, Grid Operations	Developing coordinated operational strategies to minimize wildfire risk
	Educating operational personnel on these operational strategies, the importance of reducing wildfire risk, and their specific roles in this regard
	Coordinating the implementation of wildfire strategies with other PGE departments to ensure an effective response to elevated fire risk or emergency situations in the PGE service territory
	Monitoring fire weather and active fire events to inform operational decisions and support safe and reliable operations

7.4(b) Emergency Planning

PGE's BCEM organization is responsible for maintaining PGE's Corporate Emergency Operations Plan (CEOP) and library of associated plans.

1. Fire Season Preparedness Exercise

PGE has established methods for conducting exercises consistent with national guidance and principles outlined by the Homeland Security Exercise and Evaluation Program (HSEEP). Each fire season, WM&R will take the lead in developing an exercise that evaluates PGE Wildfire Mitigation Plan viability and ensures that stakeholders understand the plan's guidance and requirements.

When possible, PGE will engage external stakeholders in their exercises to improve interoperability during an actual event. Prior to each fire season, PGE will also engage with municipal emergency managers to identify opportunities for public/private sector coordinated exercises, including (but not limited to) incident communications and safety (e.g., evacuation exercises).

Each exercise will be followed by implementation of the after-action review (AAR) process described in the PGE Resiliency Framework.

7.4(c) Event Response & Management

Following wildfire incidents, PGE will implement response operations to address the physical, psychological, social, and economic effects of the incident. Response planning provides rapid and disciplined incident assessment to ensure a quickly scalable and adaptable response.

PGE's wildfire incident response and management responsibilities are outlined in Appendix 11 of PGE's CEOP. For detailed information, please refer to Appendix 8 of this document.

1. Emergent Events and Active Incidents

PGE has established communications processes and plans for incident communications, both internally and externally. The CEOP, its various subsidiary plans, and the Communications Playbook are PGE's primary resources for incident response and management.

During wildfire incidents, BCEM is the process owner for activation of PGE's CIMT and/or Emergency Operations Center. BCEM is also responsible for maintaining PGE's library of interdepartmental incident response Plans. The decision to declare a PSPS event is made by PGE's VP Utility Operations.

During wildfire season, PGE's WM&R organization monitors local, statewide, regional and national fire and weather conditions around the clock and assesses fire potential based on a variety of situational awareness factors: active fire incidents, wind, fuels, humidity and National Weather Service forecasts. This ongoing assessment drives decisions about operational and system changes, as well as operational efficiency. During fire season, PGE's Wildfire Operations Program Management (WOPM) team meets daily and communicates its findings and recommendations to PGE Operations staff and management.

During fire season, at 7 am daily (Monday-Friday), T&D and Dispatch host the Daily Operations Call. During Red Flag Warnings and other severe weather events, Utility Operations may decide to convene the Daily Operations Call on weekends as well, and will resource this effort appropriately.

The call begins with a detailed weather briefing. During fire season, the weather briefing is followed by wildfire situational briefing. BCEM follows the wildfire situational briefing with operational situational awareness items such as security threats. Utility Operations leaders are responsible for disseminating that intelligence from the Daily Operations Call up and down the chain of command. PGE uses multiple checks and balances to ensure that fire weather is known, and on-the-ground conditions are verified, from the top down. This information is disseminated through the following processes:

- **Stand-Ups:** Pre-work briefings in the yards at service and line centers
- **Tailboards:** Pre-work briefings on the job site
- **Crew Board Communicators:** Big-screen monitors that display crew jobs, as well as the fire weather and current Industrial Fire Precaution Level (IFPL)

- **Kestrel Fire Weather Handheld Meters:** Field personnel receive training on how to measure temperature, relative humidity and wind speed at the job site using Kestrel weather meters
- **2x Radio Blasts**: Are used to reach resources who dispatch from home (Eagles, Reliability Techs). These radio briefings echo watches, warnings and critical fire danger information, and also repeatedly announce that a de-energized feeder or feeder section is about to be re-energized. PGE never re-energizes a tripped feeder without making this radio announcement twice.

Every PGE field employee is responsible for knowing what the fire weather and danger is, the IFPL for the area in which they're working, and how that impacts them (safety protocols, approved operations, required PPE and other supplemental equipment).

2. *Ignition Reporting Requirements*

For the 2021 fire season, PGE developed a mobile application to enable personnel to report data related to ignitions observed in the field. This is consistent with the OPUC's Incident Reporting Requirements (860-024-0050). After an ignition event, the Sr Manager of Wildfire Analytics, Research & Development is responsible to report ignition data back to the PUC within the timeframe set forth in the Rule.

3. *Work Schedule Adjustments & Crew Notifications*

During fire season, fire danger levels may impact operational activities and schedules. Fire danger is geographically specific -- danger levels and associated environmental precautions fluctuate depending on a crew's work location within PGE's service territory. Fire danger levels are communicated in a variety of ways (please refer to the previous section, "Emergent Events and Active Incidents," for a list of communications channels).

(b) Response – Active Event

Crews working in areas with an active wildfire will follow all rules, responsibilities and protocols in this Wildfire Mitigation Plan, the CEOP and supporting processes, procedures and guidelines, such as the Wildfire Pocket Guide. The safety of crews and the public is PGE's top priority. PGE will defer to first responder agencies when there are active fires, and will not send crews into an active fire zone unless approved by the lead first responder agency. This section will be updated to reflect the guidance in PGE's Wildfire Assessment Guide once this document is finalized (Spring 2021)

Response to and during a wildfire requires immediate assessment and incident characterization, the communication of appropriate situational awareness, and the development of an incident planning cycle to facilitate the collection, assessment, and dissemination of relevant wildfire incident information. For larger events, a Fire Coordinator may deploy to the Incident Command Post (ICP) to provide real-time situational awareness to PGE.

The Fire Coordinator serves as the primary point of contact between first responder agencies and the PGE Incident Commander. Field Operations is responsible for scene safety, along with command and control of the incident to recover the system and restore customers. The EOC's focus is on the big picture of the incident, which involves managing and deconflicting critical information, communicating to customers and key external stakeholders, and providing operational support and strategic and policy-level decision-making. Demobilization planning remains a focus during the response phase to ensure adequate recovery of the system.

A wildfire may require de-energization of electrical distribution circuit(s) and transmission tie line(s) for public or first responder safety. The Incident Commander will carefully examine whether de-energization is required based on input from field response and first responders. This type of de-energization for public or first responder safety is not considered a PSPS as it may not be triggered by a wind or Red Flag event. Rather, it is in response to unsafe conditions due to wildfire activity and therefore does not follow PSPS protocols.

Public-sector fire agencies are deployed to new ignitions and localized, low-complexity fires to protect life safety and prevent fire spread. For new ignitions or localized, low-complexity fires, a command post is unlikely to be established immediately (or easy to locate once established), nor is it likely that it will be necessary to activate a CIMT to assist in communications and logistics.

For high-complexity events and for large fires – any wildland fire in timber 100 acres or greater, or 300 acres or greater in grasslands/rangelands (as defined by the National Wildland Coordinating Group) -- a public-sector Incident Management Team (IMT) will be assigned to establish a multi-agency command post at safe proximity to the fire event. For events that may impact PGE assets and services, PGE representatives from multiple lines of business may be embedded into the public-sector IMT to coordinate situational awareness with local staff and CIMT resources.

7.4(d) Post-Fire Season Review

WM&R will conduct a review of this plan with internal and external stakeholders prior to year-end, as part of its formal post-wildfire season review process. Primary objectives of this review process include:

- Identifying and promoting aspects of the program (e.g., training, preparedness measures, operational strategies and documentation) that worked well
- Identifying opportunities to improve preparedness, operational strategies, training, work instructions, communication and other program elements
- Evaluating new ideas, improvements and observations identified by the team for future implementation
- Assigning task owners and target completion dates for corrective actions
- Identifying "next season" opportunities to improve collaboration with external stakeholders -- planning, training and exercises
- Establishing baseline goals and objectives for the next fire season.

When an AAR process is conducted during fire season due to an actual event, PGE will integrate any outstanding corrective actions into its post-wildfire season lessons learned review. As part of this review, PGE will also track ignition data from PGE equipment to identify the greatest wildfire risks in its service territory and aid us in making future improvements to our Wildfire Mitigation Program and Plan.

1. Damage Assessment

Performing ground damage assessments of electrical equipment in a burn scar can be dangerous and requires specialized clothing and training to ensure the safety of workers. Safety will always be PGE's number one priority, and deployment of personnel into a burn area will occur only after a thorough hazard/safety assessment is completed. When deploying resources to assist other electric utility operators via mutual assistance, PGE will perform the same hazard and safety assessments prior to and throughout deployment.

Ad-hoc outfitting and training of electric industry personnel has and can be provided in many instances by public fire agencies. Until a formal damage assessment program is implemented at PGE that includes specialized training and PPE, incident management and/or field personnel will coordinate through fire agency resources to establish the damage assessment team and conduct escorted ground damage assessments within restricted areas. Other options for conducting damage assessments will be evaluated first before performing ground assessments to reduce risk (e.g., air patrols and drones).

PGE's T&D Operations organization is developing a Damage Assessment Plan, which will be used to guide future wildfire (and other events impacting PGE infrastructure, such as high winds, ice storms, earthquakes) damage assessment activities. The Damage Assessment Plan will be referenced as an appendix in future iterations of this Plan. For additional information on damage assessment procedures, please refer to the FEMA Preliminary Damage Assessment Guide.

2. Recovery

PGE will follow CEOP guidance during the post-incident recovery period:

"There are two forms of recovery: short- and long-term. Short-term recovery includes temporary repairs and recovery of critical operations. Long-term recovery focuses on resuming all operations and rebuilding, which can potentially last years. During recovery, it is important to capture lessons learned and act to prevent or mitigate impacts from future incidents." (PGE Corporate Emergency Operations Plan Base Plan).

For the purposes of wildfire management, PGE will treat its End of Fire Season declaration as an event and will perform whatever recovery activities are required to bring the company back to non-fire season readiness. Any operational changes implemented for fire season shall be transitioned back to their non-fire season state.

At the conclusion of fire season and the start of the next fire season, team members for each of PGE's major wildfire mitigation program areas will participate in the post-wildfire season review process to identify lessons learned during the previous fire season, including the implementation of any potential improvements and action items. During the annual post-season review work session, members of the individual program area teams will present the results of these findings to PGE's supervisory WM&R leadership team for further evaluation, prioritization, and implementation.

In addition, PGE will follow all relevant OPUC protocols in submitting a post-event PSPS report within 10 days of the conclusion of the PSPS event. For more detailed information, please refer to the current PSPS Plan (Appendix 10).

7.4(e) Fire Danger

PGE bases its wildfire threat assessment on real-time fuels/atmospheric conditions. WM&R staff review seasonal predictions, as well as monthly, weekly and daily fire-weather forecast data, including data from

PGE's Remote Automated Weather Stations (RAWS), and communicate findings and threats to field and operational resources. These reports influence operational decision-making, such as planned, unplanned and emergency work.

WM&R's role is to provide situational and conditional awareness throughout wildfire season. PGE closely monitors all confirmed fire events within proximity to PGE infrastructure, as well as available firefighting resources on a local, statewide, regional and national level. That information drives local and regional Preparedness Levels (PL), which range from 1 (ample resources available) to 5 (significantly limited resources). WM&R summarizes this information in the daily wildfire operations briefing: active Northwest fires, significant fire potential, fire weather forecasts across T&D service territory, fuel conditions and other links to publicly available data, such as https://gacc.nifc.gov/nwcc/content/products/intelligence/MORNINGBRIEF.pdf.

During wildfire season, PGE field supervisors monitor weather and threat data for the areas their crews will be working in and communicate it during their daily standup briefings and job-specific tailboard briefings. PGE field crews are trained to validate forecasted fire weather conditions through a Kestrel handheld fire weather meter. If field weather conditions are reported to be different – for example, if winds are higher than forecasted – field verification may result in changes to crew work assignments or location.

1. *Situational and Conditional Awareness*

PGE relies on real-time situational and conditional awareness information and forecasts to develop its daily fire potential assessment. In 2021, it is improving its situational awareness through the installation of new automated weather stations along with four mobile weather stations to be deployed in PSPS areas. In addition, PGE is continuously enhancing these capabilities through partnerships with first responders, municipal emergency planners, state agencies and industry partners.

(b) Methodology for Identifying Fire Season and Evaluating Wildfire Related Risk

To determine the start or end of fire season, PGE's WM&R organization, with input from BCEM, Line Operations and the SCC, will monitor current weather conditions, fire weather forecasts and other information. They will use a variety of wildfire risk assessment tools to obtain a precise view of PGE's current fire risk environment, including:

Wildfire Notification Tool: A GIS-based, real-time analytical tool that emails PGE wildfire managers directly (with attached pdf map and link to an online AGOL map) whenever a threat is detected within five miles of any PGE infrastructure. The tool tracks threats in the following four categories:

a. Red Flag Warnings as designated by the National Weather Service
b. Moderate Resolution Imaging Spectroradiometer (MODIS) thermal anomaly (hot spot) with confidence rating above 50
c. Integrated Reporting of Wildland Fire Information (IRWIN) wildfire location
d. IRWIN-established wildfire perimeter.

Comprehensive Wildfire/Hazard Map: An interactive, web-based map that includes wildfire locations, Red Flag Warnings, lightning strikes, high-risk areas, and other data.

Other sources of conditional awareness data used by PGE in the Fire Season Declaration process include:

a. https://www.weather.gov/fire/
b. https://www.oregon.gov/ODF/Fire/Pages/Weather.aspx#NOAA
c. https://www.oregon.gov/ODF/Fire/Pages/Restrictions.aspx
d. https://gacc.nifc.gov/nwcc/.
e. https://weccgeo.maps.arcgis.com/apps/dashboards/0577a7b0ae3f495492f0b478a63c70ca

As described in section 6.4 (e) 1.0 of PGE's Fire Season Start and End Declaration procedures, the Vice President of Utility Operations, or designee, shall evaluate the information provided and declare the start and end of the wildfire season for the PGE service territory, or for a region within the territory. WM&R partners with PGE's Meteorology Department to recommend the start and end dates for PGE fire season.

(c) Early Wildfire Detection

PGE participates in the ALERTWildfire Early Fire Detection program. The ALERTwildfire camera network is a situational awareness tool built by the University of Nevada, Reno (UNR), University of California San Diego (UCSD), and University of Oregon (UO). The high-definition, pan-tilt-zoom cameras allow PGE as well as firefighters and first responders to confirm and monitor potential wildfires via the ALERTWildfire network. WM&R now has a process in place to allow individual agency partner representatives to control the cameras to increase situational awareness as needed.

The cameras allow PGE and its partners to

- Discover, locate, and confirm fire ignition
- Quickly scale fire resources up or down in response
- Monitor fire behavior from ignition through containment
- Precisely target evacuation efforts during firestorms, through enhanced situational awareness
- Verify that contained fires are monitored appropriately until fully extinguished.

The UO Oregon Hazards Lab uses a hardened telemetry system for the data communications links used to operate the ALERTWildfire cameras, extending the reach of the fiber-optic network LinkOregon has deployed and operates across the state.

PGE installed two ALERTWildfire cameras in 2020, both overlooking PGE's Mt. Hood Corridor PSPS zone in Clackamas County -- one at Brightwood and the other at Timberline. Future sites will be chosen based upon PGE's experience in recent and upcoming fire seasons, and its evaluation of the current camera network.

(d) Remote Automated Weather Stations (RAWS)

To improve its situational awareness of wildfire threat conditions, PGE installed two weather stations in PGE's Mt Hood PSPS zone in Clackamas County. The weather stations, installed on existing PGE infrastructure by Western Weather Group, are equipped with temperature, relative humidity, fuel moisture, rain and wind speed/direction sensors. The stations can transmit the collected data via cellular or satellite service, depending on availability. The data is hosted externally and available for review by PGE's meteorologists on demand. In 2021, PGE is planning to install additional remote weather stations in its PSPS zones.

1. *Fire Season Start and End Declaration*

The PGE-declared Fire Season start and end dates vary from year to year; in 2020, PGE declared the start of fire season on July 1 and the end of fire season on October 23 (west of Cascade Crest) and November 6 (east of Cascade Crest). PGE's Vice President of Utility Operations is responsible for declaring the Fire Season start and end dates in accordance with PGE's fire season start and end procedures (Appendices 5 and 6 of this document). Depending on in-season conditions, PGE may choose to declare different dates for the start and end of wildfire season east and west of Cascade Crest. This two-zone approach is reflected in the SCC Fire Risk Mitigation Procedures as well.

(e) Operational Overview of System Control Center's (SCC) Fire Risk Mitigation

System operators and staff will follow the guidance in PGE's SCC Fire Risk Mitigation procedures (Appendix 7 of this document) to mitigate fire danger risk when PGE T&D system faults occur. The SCC Fire Risk Mitigation procedures limit the use of line testing and automatic reclosers during fire season (and outside of fire season during periods of elevated fire danger).

Prior to the declared start of fire season, PGE engineers review and update settings for protection and control devices in PGE's wildfire risk areas to reduce the likelihood of utility-caused wildfire ignition. On transmission lines, reclosers are used to quickly re-energize circuits after they are de-energized by a fault. If a line or circuit trips because of an overcurrent, the automatic recloser opens, deenergizing the line or circuit. After a preset time, the device closes again, which reenergizes the line or circuit. If the condition that caused the overcurrent (such as a tree branch) is still in contact with the circuit, the device opens again. Many of PGE's pre-fire season system protection settings changes have to do with reclosers, including:

- *Enable non-reclose protection settings for TripSaver II (TSII) Reclosers:* PGE line crews have now installed reprogrammed TSII devices in PGE PSPS areas and enable their non-reclose setting during wildfire season. At the conclusion of fire season, line crews re-enable reclosing by disengaging the non-reclose handle.
- *Enable wildfire mitigation setting on Electronic Reclosers:* PGE's Electronic reclosers are now integrated with SCADA, the computerized system that allows PGE to monitor and control its distribution systems. This allows PGE system operators to enable the Wildfire and Red Flag modes during fire season.
- *Hydraulic Reclosers:* Prior to wildfire season, line crews visit each hydraulic recloser in the PGE system to enable the non-reclose setting in PSPS zones. At the conclusion of fire season, line crews re-enable reclosing.
- *Substation Equipment:* PGE has implemented a delayed instantaneous setting on its 13 kV feeders , as well as sequence coordination on these feeders (on those SCADA-controlled feeders equipped with SEL relays). In addition, Welches-Zig Zag now has High Impedance Fault (HIF) protection, which alerts (but will not trip for) a downed conductor.

During wildfire season, all of PGE's 13 kV feeders with SEL relays and SCADA operate in their respective Wildfire mode -- one shot of reclosing and definite time instantaneous. When WM&R determines that fire risk conditions are extreme, system operators will enable Red Flag mode on these feeders – definite time instantaneous tripping and reclosing blocked. Normal and Wildfire modes can also be selected via pushbutton on the front of the relay; Pelton has an additional pushbutton for Red Flag mode. PGE's 13 kV feeders with electromechanical (E-M) relays will operate normally if there are no downstream electronic reclosers, on Red Flag days those feeders will be placed in Hot Line Tag/Hold which enables instantaneously tripping, and blocks reclosing. If there are downstream electronic reclosers, instantaneous tripping is blocked on the E-M relays, and the reclosers are set up for wildfire operations.

Once wildfire season has been declared, PGE will implement a number of additional wildfire-related operational changes. For example, if a feeder breaker opens, recloses, and holds, system operators can now block all subsequent reclosing on the feeder breaker until line crews can patrol the entire feeder to clear the fault. Subsequently, if a recloser opens, line crews will patrol the circuit downstream of the recloser, prior to closing the recloser back in.

PGE system operators also coordinate system protection changes during fire season. PGE is opportunistically replacing expulsion fuses with non-expulsion ELF fuses, and overhead expulsion tap line fuses with CMU mountings with E-style fuses. Additional protection coordination will occur as the protection changes over time.

(f) External Notification of Fire Season

The following table describes key tasks associated with notifying external stakeholders of PGE's fire season start and demobilization. All activities will be completed in coordination with PGE Brand, Marketing & Communications.

TABLE 9: EXTERNAL NOTIFICATION TASKS AND RESPONSIBILITIES

Product or Task	Description	Frequency	Responsible
Wildfire Season Start – City of Portland, County Emergency Management, and ESF-12	Email notification to affected county and city emergency managers that PGE has declared the start of wildfire season. Email must include any relevant updates to key contact information for PGE emergency management personnel.	Annual	BCEM
Wildfire Season Start – OPUC	Email notification to the OPUC/ESF 12 that PGE has declared the start of wildfire season. Email must include references to any Plan sections detailing changes in PGE operating practices and emergency communications.	Annual	Rates and Regulatory Affairs

Wildfire Season Start – Governmental Entities	Email notification to key governmental stakeholders in high-impact areas that PGE has declared the start of wildfire season.	Annual	Government Affairs Key Customer Management
Wildfire Season Start – Key Customers	Email notification to key customers in high-impact areas that PGE has declared the start of wildfire season.	Annual	Key Customer Management
End of Wildfire Season – All entities	Email notification to all of the entities listed above that PGE has declared the end of wildfire season, that the company is demobilizing for wildfire season, and is moving on to winter storm preparedness activities. Annual Start and End of Wildfire Season declarations are documented in the Vital Records for Start and End of Wildfire Season SharePoint site, including supporting decision rationale documentation from WOPM and PGE Meteorologist	Annual	WM&R

(g) Wildfire Season Monitoring and Communication

Even during active wildfire seasons, PGE may not be directly impacted by a wildfire. However, coordinated monitoring and communication of situational awareness information is essential to effective and rapid PGE response to incidents. The following table describes some of the situational awareness tools PGE uses during fire season.

TABLE 10: FIRE SEASON MONITORING & COMMUNICATIONS TASKS AND RESPONSIBILITIES

Product or Task	Description	Frequency	Responsible
Fuels & Weather Forecasts	Regional and national "Significant Wildland Fire Potential Outlook" distributed via email to the fire season distribution list.	March – October, as needed	WOPM & PGE Meteorologist
Emergency Notification System (ENS)	Multi-mode communication technology utilized to notify PGE staff of potential or declared emergencies that threaten staff, assets, facilities, or the public.	Throughout the year, as needed	BCEM
Daily Operations Briefings	Operations briefings to update staff on current or expected Wildfire	Weekdays throughout fire season; may be seven days	WOPM

Product or Task	Description	Frequency	Responsible
	Season conditions and short-term forecasts.	a week during severe weather/RFW periods	
Threat Alerts	WOPM, BCEM and/or GIS distribute threat alerts to PGE personnel with emergency responsibilities, including T&D, Generation, and CIMT resources. Alerts are distributed when significant threats are forecasted to occur or are occurring that can impact service to customers and/or create safety hazards for personnel and the public. The National Weather Service is typically the primary source of this information, although other resources may also be used.	Throughout the year, as needed	WOPM, GIS
GIS Red Flag Warning	Automated email notifications (via GIS) RFWs in the PGE service territory.	Throughout fire season	WOPM & GIS
GIS Warnings for potential fires within 5 miles of PGE facilities	Automated email notifications via GIS when IRWIN and other external wildfire resources indicate a potential for a fire within 5 miles of a PGE transmission or generation facility.	Throughout fire season	WOPM & GIS
Crew Board Sit Stat	Notifications of RFWs or other conditions (IFPL changes) displayed on crew boards at distribution line centers for purposes of communicating current wildfire situational status to line crews.	As needed throughout fire season	Distribution Line Operations
Tailboards and Stand-ups	Supervisors from multiple PGE departments conduct tailboards in the field and stand-up meetings for field personnel to communicate current and forecasted conditions when RFWs or other conditions may affect operational practices.	As needed throughout fire season	All field leadership

7.4(f) Public Safety Power Shutoffs

During extreme weather, PGE may initiate a temporary PSPS to prevent PGE's electric system from becoming a wildfire ignition source. Due to the disruptive nature of a power outage, PGE will execute all PSPS events safely, with the least possible disruption to the community, and only when necessary. PGE's PSPS protocols and procedures are described in the annual PSPS Plan, produced by PGE's WM&R organization (Appendix 13 of this document). The purpose of the PSPS Plan is to reduce the risks from wildfires within PGE's service territory and in areas adjacent to PGE critical infrastructure throughout the Northwest through proactive de-energization.

PGE's PSPS plan describes PGE's PSPS execution protocols, and the policies and procedures that guide PSPS implementation. The plan details the actions PGE takes to prepare for, respond to, and recover from a PSPS event. This plan may also be used to guide PGE actions during non-wildfire events when a pre-emptive power shut-off is needed to protect the community and grid – for example, during a cyberattack targeting the bulk power system, during other natural disasters, or during a severe structure fire.

PGE maintains current contact lists for the public safety partners, critical facilities, and vulnerable populations within each PSPS Zone, and will follow all relevant OPUC notification protocols in communicating with these stakeholders before, during and after PSPS events. In addition, PGE will follow all relevant OPUC protocols in coordinating with its public safety partners, emergency response centers and incident command centers before, during and after PSPS events. For more detailed information, please refer to the current PSPS Plan (Appendix 10), Wildfire Communications Plan (Appendix 11), Wildfire Outreach Plan (Appendix 11) and Agency Engagement Plan (Appendix 13).

7.5. Stakeholder Engagement

The term "stakeholder" indicates both key internal and external resources needed to help ensure preparedness for each fire season. Where possible, PGE will help lead collaborative efforts between public and private sector entities to improve collaboration before, during and after fire season.

Goals and objectives of PGE's public and agency outreach and engagement activities include:

- Enhanced public/private partnerships to facilitate life safety, identifying vulnerable populations, property conservation, incident stabilization and continuity of agency services
- Improved critical infrastructure resilience through planning and coordination with external agencies.
- Improve coordination of emergency response, situational and conditional awareness
- Enhance PGE's wildfire planning, prevention and response through coordination, communication, and collaboration with external partners
- Improve understanding of external stakeholder vulnerabilities and values-at-risk (economic, social, and ecological resources that could be damaged because of a wildfire)
- Educate external stakeholders on PGE's risk management activities and potential consequences to critical infrastructure from wildfires
- Strategize and pre-plan effective, mutually beneficial, coordinated responses to prevent incidents, save lives and facilitate the rapid recovery of essential service
- Promote learning and adaptation during and after exercises and incidents
- Facilitate the continuity of emergency services during gray and blue-sky events.

7.5(a) Roles & Responsibilities

Key Customer Management	Identify key customers affected by wildfire operations
	Communicate and liaise with key customers impacted by wildfire-related events
	Share pertinent information with key customers before, during and after events
	Relay key customer concerns and needs back to the appropriate groups and individuals at PGE
	Identify external partners for wildfire planning

Wildfire Mitigation & Resiliency	Operational planning to support response and recovery
	Sharing of situational awareness data
	Agency resource allocation
	Logistical support opportunities
	Supporting and championing all available safety measures
	Evacuation preparedness for PGE facilities, including PGE parks and guests
	Participation in and facilitation of training and exercises
	Communications solutions to mitigate barriers between stakeholder groups

Government Affairs & Local Government Affairs	Identify critical stakeholders and partners for PSPS planning and activation
	Share timely information before, during, and after events (Local, city, county, state, federal)

Brand, Marketing & Communications	Develop wildfire preparedness PSPS Communication and Outreach Plan for impacted areas, including proactive communication in collaboration with local agencies and officials to help affected communities prepare for a wildfire
	Develop PSPS-related communication messages / awareness for both internal and external audiences
	Develop communication messages and supporting materials targeted to customers directly impacted or potentially impacted by Wildfire mitigation measures

7.5(b) Public Awareness

Prior to and during wildfire season, PGE will communicate with customers and the public to share wildfire preparedness information and situational updates, as well as PSPS announcements, via mass channels, including text, email, telephone, internet and media statements. Wildfire-related public communication is a team effort, primarily the responsibility of PGE's Brand, Marketing & Communications, Government Affairs, Key Customer Management and Corporate Communications organizations.

PGE will proactively use the full range of paid, earned and owned channels to communicate key wildfire-related information to customers impacted by wildfire activity. As needed, PGE will disseminate wildfire-related information through local and state community partners.

7.5(c) Customer Support & Communications

1. *Customer Outreach*

PGE will work with the community prior to and throughout wildfire season to keep customers informed on PGE's wildfire season activities. Prior to each fire season, PGE will establish a detailed Wildfire Communications & Outreach Plans (Appendix 11). The following table provides a high-level overview of key PGE customer outreach tasks.

TABLE 11: CUSTOMER OUTREACH TASKS AND RESPONSIBILITIES

Product or Task	Description	Frequency	Responsible
Customer Communication	Notifications to customers of the potential for increased tree trimming and other preparedness activities in their area.	As needed	Brand, Marketing and Communications
Customer Communication	For customers in high-risk areas, communications regarding potential for proactive de-energization of lines (PSPS event) in the event of an RFW or fire in close proximity.	As needed	Brand, Marketing and Communications, Government Affairs, Key Customer Management
Customer Communication	Outreach to inform customers of risks during fire season and work being undertaken by PGE to help ensure uninterrupted delivery of electrical service during fire season.	As needed	Brand, Marketing and Communications

For additional details regarding PGE's customer communication strategies, please refer to PGE's current Public Safety Power Shutoff and Wildfire Communications and Outreach Plans (Appendices 11 and 12, respectively, below).

7.5(d) Working with Federal, Tribal, State & Local Agencies

PGE will follow all relevant OPUC protocols governing the reporting of wildfire incidents, serious injury to persons or property, or loss of service. This responsibility is shared between PGE's Government Affairs, Utility Operations, WM&R, and Legal organizations, depending on the nature of the incident. In addition, PGE will follow all relevant OPUC protocols in submitting a post-event PSPS report within 10 days of the conclusion of a PSPS event. For more detailed information, please refer to the current PSPS Plan (Appendix 10).

PGE's Wildfire Agency Engagement Plan (Appendix 13, below) describes a systematic, risk-based approach to directing and prioritizing PGE's interactions with outside agency stakeholders both during and outside of fire season. To maximize the effectiveness of its wildfire preparation and mitigation efforts, PGE collaborates with a variety of external stakeholders such as state regulators, interconnected electric utilities, first responders and emergency managers.

The purpose of the Agency Engagement plan is to provide a framework and process for PGE's annual wildfire-related engagement activities, including PSPS and reactive de-energization requests, involving external agency stakeholders: government agencies, state cooperators, Tribes and authorities having jurisdiction (AHJ).

The intent of PGE's wildfire agency engagement planning is to assist PGE and its agency partners in collaborating and co-navigating wildfire threats through preparation, effective coordination, and communication. The annual Wildfire Agency Engagement Plan describes which agencies PGE engages with, the annual schedule for strategic meetings, and the key activities requiring agency engagement and coordination.

These coordinated key activities include:

- Collaboration with agency stakeholders to effectively prepare for, respond to and recover from wildfire threats and events
- Coordination of in-season public safety actions
- Actions to reduce the risk of utility-caused wildfire ignitions.

Agency partnerships are crucial to maximizing the effectiveness of PGE's wildfire preparation and response. Shared threats to life and safety, property and cultural resources, and a common interest in incident stabilization and the protection of life, property and infrastructure make effective agency partnerships a crucial component of PGE's wildfire mitigation efforts. Close collaboration with agency partners helps all participants optimize use of available resources and avoid duplication of effort.

PGE annually undertakes a variety of activities intended to strengthen collaboration with agency partners and the effectiveness of our shared wildfire response. PGE will attend agency-hosted review and planning events, host agencies for tours, open houses and workshops, provide access to PGE wildfire cameras and weather data, provide utility safety training, and educate stakeholders on PGE resource capabilities, limitations and best practices.

Hosting and participating in these collaborative events will increase PGE's understanding of the impact of PGE decisions, such as PSPS, on our agency partners and their capabilities. This will also facilitate an increased understanding of each agency's limitations, capabilities, gaps and assumptions, to help guide PGE's deployment of training, equipment, supplemental generation and field crews.

PGE's specific pre-season activities include participation in or hosting of:

- Fire season kickoff meeting

- Municipality Emergency Management Forums
- Northwest Interagency Coordination Center (NWCC) Annual Meeting
- United States Forest Service and Oregon Department of Forestry coordination meetings
- Annual Critical Infrastructure Meeting

For additional details regarding federal, tribal, state and local outreach activities, please refer to PGE's current Agency Engagement Plan (Appendix 13).

1. *Fire Season Agency Outreach Activities*

TABLE 12: PRE-FIRE SEASON AGENCY OUTREACH ACTIVITIES

Pre-Fire Season PGE / Agency Annual Engagement and Outreach Schedule			
Tactic / Deliverable	**Process Owner**	**Contributors (as needed)**	**Timing**
Participating in agency-facilitated field, virtual or blended exercises, trainings, and meetings, as requested	Wildfire Operations Program Management (WOPM)	TBD, based on event	As requested and available
Conducting pre-fire season planning and preparedness workshops with agency stakeholders	WOPM	Business Continuity and Emergency Management (BCEM), Government Affairs (GA), Local Government Affairs (LGA), Key Customer Management (KCM), Utility Operations, Environmental, Geographic Information System (GIS), Legal, Parks	April
Creating an action register to ensure that all pre-fire season agency questions, concerns and suggestions raised in planning and preparedness workshops are addressed internally and reviewed with the requesting agency in a timely manner	WOPM	BCEM, GA, LGA, KCM, Rates and Regulatory Affairs (RaRA), Brand, Marketing and Communications (BMC), Security, Legal, Utility Operations, Environmental, GIS, Information Technology (IT)	April
Facilitating PGE-led virtual or blended exercises and training with internal and external stakeholders	WOPM	BCEM, GA, LGA, KCM, RaRA, BMC, Security, Legal, Utility Operations, Environmental, GIS, IT, Parks	May
Participating in wildfire preparedness meetings with County emergency managers	WOPM	BCEM, GA, LGA, KCM, Legal, GIS, Parks	April – PGE Fire Season Declaration

2. *Fire Season Agency Outreach Activities*

TABLE 13: FIRE SEASON AGENCY OUTREACH ACTIVITIES

Fire Season PGE / Agency Engagements			
Tactic / Deliverable	Process Owner	Contributors (as needed)	Timing
Participating in agency meetings, trainings, and site visit requests	WOPM	BCEM, GA, LGA, KCM, RaRA, BMC, Security, Legal, Utility Operations, Environmental, GIS, IT, Parks	As needed and available
Wildfire response	WOPM	BCEM, GA, LGA, KCM, RaRA, BMC, Security, Legal, Utility Operations, Environmental, GIS, IT, Parks	Per incident
PSPS	WOPM	BCEM, GA, LGA, KCM, RaRA, BMC, Security, Legal, Utility Operations, Environmental, GIS, IT, Parks	Per event
Agency led-After-Action Reviews (AAR)	WOPM	BCEM, GA, LGA, KCM, Security, Legal, Utility Operations, GIS, Generation Operations, Parks	As requested and available

3. *Post-Fire Season*

TABLE 14: POST-FIRE SEASON AGENCY OUTREACH ACTIVITIES

Post-Fire Season PGE / Annual Agency Engagement and Outreach Schedule			
Tactic / Deliverable	Process Owner	Contributors (as needed)	Timing
Developing annual agenda for agency engagement and outreach meetings	WOPM	BCEM, GA, LGA, KCM, RaRA, BMC, Security, Legal, Utility Operations, Environmental, GIS, IT, Parks	End of PGE Fire Season – EOY
Participating in agency-facilitated after-action reviews (AAR), as requested	WOPM	BCEM, GA, LGA, KCM, Security, Legal, Utility Operations, Environmental, GIS, Parks	As requested
Participating in agency-facilitated field, virtual or blended exercises, trainings, and meetings, as requested	WOPM	TBD, based on event	As requested and available
Conducting post-season review workshops with agency stakeholders	WOPM	BCEM, GA, LGA, KCM, Utility Operations, Environmental, Legal, GIS, Parks	February
Creating an action register to ensure that all agency post-season questions, concerns and suggestions are addressed	WOPM	BCEM, GA, LGA, KCM, RaRA, BMC, Security, Legal, Utility Operations, Environmental, GIS, IT, Parks	February

internally and reviewed with the requesting agency in a timely manner			

7.5(e) First Responder Support

PGE will actively participate in all Incident Management Team (IMT) and CIMT meetings to support Oregon first responders. For additional details regarding first responder outreach activities, please refer to PGE's current Agency Engagement Plan (Appendix 13).

Reasons a first responder fire dispatch center may contact the PGE Dispatch or System Control Center include:

- Wire down or, low-line (sagging wire) notification
- Notification of fire crews working near power lines, natural gas facilities or energy communication equipment and related requests to de-energize facilities
- Requests for PGE representation at an Incident Command Post/IMT participation
- Notification of firefighting tactics that may impact electrical facilities and services
- Notification of new ignitions that are impacting or may impact energy facilities.

7.5(f) Industry Engagement

Emergency managers from PGE, PacifiCorp, Northwest Natural Gas, and BPA collaborate throughout the year as part of an Energy Emergency Management Team (EEMT). Annually, EEMT exchanges contact information with the Northwest Interagency Coordination Center (NWCC) for emergency communications during fire season. Dispatch/Control Center numbers provided by the energy companies are for dispatch-to-dispatch communications. Emergency management contacts are provided for both NWCC and fire dispatch center personnel to assist with strategic decision-making and incident coordination.

In addition, PGE annually participates in a variety of industry forums that may discuss wildfire-related topics, including

- **International Wildfire Mitigation & Resiliency Consortium**: PGE participates with utilities from across the Western U.S., South America and Australia to benchmark and share best practices for wildfire mitigation.
- **Electric Power Research Institute (EPRI):** PGE engages with its research partners at EPRI through multiple programs to address wildfire mitigation research and is leveraging EPRI-led programs such as the Incubatenergy Network to gain knowledge of new technologies and start-ups in wildfire-related disciplines. As a result of its collaboration with EPRI, PGE is deploying an Early Fault Detection pilot project in 2021.
- **Other Forums:** PGE is also actively engaged with industry research partners at the Western Energy Institute, Edison Energy Institute, and the U.S. Department of Energy.

7.6. Research & Development

PGE is undertaking a variety of wildfire-related research projects with public and private research institutes and industry partners. In part to inform these efforts, PGE's Line Operations organization conducts an annual review of overhead distribution infrastructure in PSPS zones to recommend and implement potential solutions for wildfire-related system hardening measures.

Thanks to earlier R&D efforts, PGE's Remote Sensing project has now captured LiDAR and Hyperspectral imaging across our entire service territory. This detailed picture of vegetation proximity, tree species and health is helping PGE to understand precisely where risk is concentrated near our transmission and distribution infrastructure, so that we can optimally direct vegetation management activities.

PGE is also working with a consortium of industry partners in EPRI's Incubatenergy Network to explore deployment of artificial intelligence and imaging technology to automatically detect wildfires through video imaging.

TABLE 14: WILDFIRE-RELATED R&D PROJECTS

Program	Responsible Group	Responsible Position
Early Fault Detection	Wildfire Mitigation & Resiliency	Manager, Wildfire Analytics Research & Development
Smart Faulted Circuit Indicators	Distribution Engineering, SCC Operations, Field Operations	Manager, Distribution Automation & Control
Use of AI and Camera Technology to Automatically Detect Wildfires Through Video Imaging	EPRI Incubatenergy Network/WM&R	Manager, Wildfire Analytics R&D

7.6(a) Technologies Under Evaluation

1. Early Fault Detection

In 2021, PGE is deploying an Early Fault Detection system that uses radio frequency signals to detect and pinpoint potential failures on our distribution system in high wildfire risk areas. This technology, if proven successful, will pinpoint potential failure well before traditional methods such as physical inspection.

2. Remote Sensing Project

Remote sensing information, such as LiDAR, is emerging as a utility best practice for accurately assessing infrastructure, facilities, and vegetation to better understand wildfire risk and inform mitigation strategy. After a comprehensive evaluation of the impacts and benefits of high-fidelity data captured via remote sensing technology, PGE launched a project to capture and operationalize data from three such technologies:

- Aerial LiDAR

- Hyperspectral imaging
- High-resolution orthoimagery

PGE's Remote Sensing project, completed in 2020, captured detailed topographical and measurement data for PGE's entire distribution service territory, as well as the full length of the transmission lines owned and operated by PGE both within and outside PGE's service territory.

The data and analysis produced by this project is impacting PGE's fire risk assessment capabilities in the following key areas:

- Empirical assessment of vegetation clearance risk across the T&D infrastructure enables vegetation management practices that accurately prioritize high-risk areas first
- Data about vegetation species, density, and health is enhancing fire risk assessment
- Highly accurate data about the location and condition of T&D infrastructure is improving planning and remediation activities for assets targeted for system hardening improvements or other wildfire risk mitigation efforts.

7.6(b) Knowledge Sharing & Industry Engagement

PGE annually participates in a wide range of industry forums to stay abreast of current wildfire-related meteorological, research and development, system hardening, inter-agency coordination and regulatory developments. These activities change from year to year, but include:

- Workshops
- Exercises
- Committee membership/participation
- Speaking events
- Data sharing
    - GIS map overlays
    - Collaborative public facing platform
    - Shared access to ALERTWildfire camera and remote automated weather station data
- PSPS & wildfire incident-specific interactions.

Section 8. Quality Control & Continuous Improvement

Wildfire Mitigation & Resiliency Director	Participating in the annual review and update of fire season plans, guides, policies and procedures with operational and corporate personnel
	Participating in the annual review and update of fire season plans, guides, policies and procedures with operational and corporate personnel
	Evaluating fire season policies and regulatory requirements, coordinating work efforts to evolve fire program strategies and tactics to ensure PGE efforts meet or exceed requirements

Wildfire Mitigation & Resiliency WOPM	Facilitating PGE's year-end annual review/lessons learned process, gathering data and action items, producing year-end report
	Assign action items to a task owner, tracking tasks to completion, reporting progress
	Together with Legal, Government Affairs and RaRA, conducting an annual review of applicable OPUC and other regulatory requirements, facilitate operational and documentation updates when requirements change

PGE leadership has recognized the growing threat wildfire represents to PGE infrastructure and the communities it serves and is committed to continuously improving its wildfire mitigation program. The core of that continuous improvement effort is a formal year-end program review/lessons learned processes, involving both internal and external stakeholders. PGE's WOPM organization facilitates the review process, collecting and analyzing findings, producing the year-end report, and tracking action items.

Only through thorough post-season and post-incident review processes can PGE optimize its wildfire-related preparedness, operational and communications processes. The findings from these analyses are the basis for PGE's annual wildfire program and documentation update processes. PGE's WOPM organization is responsible for assigning action items to the appropriate task owner, tracking action item progress through to completion, and reporting progress to PGE's Executive Operations and Executive Risk Steering Committees. Examples of action items assigned following the 2020 wildfire season AAR process include:

- Stationary staging areas operations and setup
- Damage assessment improvements
- Mobile capabilities operations and setup

In addition, PGE conducts an annual review of applicable OPUC and other regulatory requirements to ensure continued wildfire compliance and updates operational procedures and documentation when requirements change.

PGE is committed to meeting 100% of the performance metrics described in the 2021 Wildfire Mitigation Plan, and to accomplishing 100% of the action items identified through the annual wildfire AAR process. Wildfire program managers conduct monthly and annual performance reviews to ensure that applicable metrics are achieved. In addition, PGE will continuously improve its wildfire mitigation performance through active participation in outside industry groups, and wildfire-related research and development.

8.1. Roles & Responsibilities

Wildfire Mitigation & Resiliency WOPM	Facilitate year end program review
	Collect and analyze review findings
	Develop and distribute annual wildfire year-end report
	Assign review action items to appropriate task owner
	Track action items through DevonWay quality management system and report outcomes to appropriate executive committee

Wildfire Mitigation & Resiliency Director	Lead wildfire year-end review process
	Facilitate annual review and update process for PGE Wildfire Mitigation Program
	Facilitating annual review and update process for PGE Wildfire Mitigation Plan and associated appendices and sub-plans (Agency Engagement, PSPS etc.)

8.2. Monitoring & Audit

PGE's Wildfire Mitigation & Resiliency, Vegetation Management, BCEM and Utility Asset Management organizations will collaborate in the development of Wildfire Program performance metrics and the completion of an annual performance audit. In addition, these organizations will annually review current OPUC and other regulatory requirements, assess PGE's ongoing compliance with applicable requirements, and update plans, procedures, engineering standards and facilities as needed to maintain compliance.

8.3. Employee & Contractor Training

1. Training

Prior to the start of fire season, WM&R will conduct annual computer-based Wildfire Awareness Training for PGE employees and those acting on behalf of PGE, to ensure that all PGE personnel who could encounter or contribute to wildfire-related risk are adequately trained and equipped. Training topics and objectives include:

- Wildfire prevention
- Wildfire preparedness
- Hazard identification, mitigation, and avoidance
- Wildfire operational safety
- Environmental factors
- Fire suppression tools and equipment
- Lookouts
- Communications
- Escape routes
- Safety zones (LCES)
- Fire weather forecasts
- Field fire weather measurements.

2. Fire Season Safety Work Instruction for Field Personnel

PGE has developed a Wildfire Pocket Guide as part of its CEOP, detailing work instructions for field crews during fire season. The purpose of this guide is to enhance worker safety during fire season by:

- Creating a standard wildfire communications process
- Preventing wildfire ignition

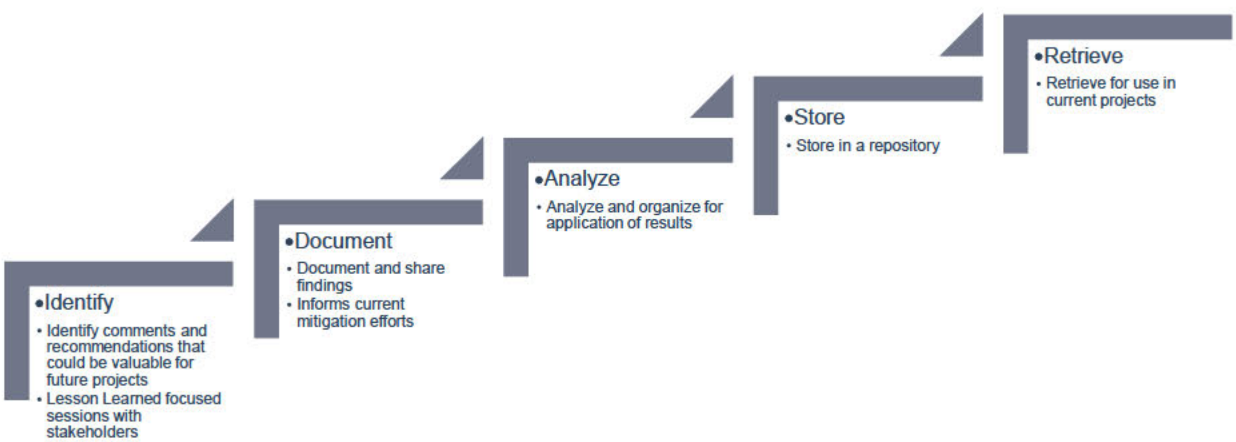
- Ensuring that, if a fire begins, employees are trained and equipped to extinguish the fire or escape (and guide others) to safety.

8.4. Lessons Learned Process

Thorough post-season and post-incident lessons learned processes are essential to the continuous improvement of PGE's wildfire prevention and response efforts. Through a formal post-season ear-end review process, PGE and its external partners identify problems and process improvements that are a crucial component of PGE's annual wildfire program review. The annual wildfire year-end review report/lessons learned process is facilitated by PGE's WM&R organization.

The year-end review/lessons learned process will include:

- Conduct an AAR process following all major wildfire incidents, as needed
- Annual post-wildfire season review workshop involving both internal and external stakeholders, with detailed notes
- Documentation and distribution of lessons learned and AAR findings – identification of comments and recommendations to improve PGE's wildfire preparedness, system hardening and operational readiness
- Annual post-season review of PGE's wildfire mitigation performance metrics and targets
- Incorporation of lessons learned findings into the annual report, used to update PGE's wildfire mitigation program and documentation
- Documentation of each year's lessons learned and year-end review findings, as well as performance metric outcomes, in PGE's Wildfire Program SharePoint library, for future reference.



Section 9. Wildfire Risk Mitigation Performance Measures

PGE's wildfire risk mitigation performance measures include three primary categories of metrics:

- **Program Measures**: Capture the specific tasks PGE intends to perform to improve wildfire mitigation, as identified in the annual Wildfire Mitigation Plan
- **Progress Measures**: Milestones capturing PGE's progress toward completing the specific performance metrics identified in the annual Wildfire Mitigation Plan
- **Outcome Measures:** Estimate the amount of wildfire risk PGE has mitigated through achievement of each performance metric.

9.1. Program Targets & Metrics

In 2021, PGE will track performance on a wide range of Wildfire Mitigation Program targets and metrics, including inspection/patrol, vegetation management, asset management, maintenance, risk management, operations, stakeholder engagement, and R&D goals. If possible, PGE will verify 100% achievement of its Wildfire Mitigation compliance requirements and performance objectives.

9.2. Outcome Metrics

To the greatest feasible extent, PGE will also track the outcome of its 2021 Wildfire Mitigation Program activities by estimating the amount of wildfire risk PGE has mitigated through achievement of these performance measures. Wildfire Mitigation Program stakeholders are working to identify a wildfire risk reduction estimate methodology and will report the outcome of these efforts in the following years' PGE Wildfire Mitigation Plan.

Appendices

Appendix 1. List of Tables

Appendix 2. List of Figures

Appendix 3. Glossary

Cycle Buster: A tree that grows closer to the circuit than anticipated by the two-year maintenance cycle, due to overfertilizing or other favorable growth conditions. PGE trims "cycle-buster" trees to increase clearances whenever they are encountered during the inspection cycle.

Fire Season: Period(s) of the year during which wildland fires are most likely to occur, spread, and affect resources sufficiently to warrant organized fire management activities.

Fire Weather: Weather conditions that influence fire ignition, behavior and suppression.

No-Test Policy: PGE will disable auto-reclosing and not manually close-in a faulted circuit.

Red Flag Warning: A term used by fire-weather forecasters to call attention to limited weather conditions of particular importance that may result in extreme burning conditions. It is issued when it is an ongoing event, or the fire weather forecaster has a high degree of confidence that Red Flag criteria will occur within 24 hours of issuance. According to the National Weather Service, Red Flag Warnings will be issued whenever a geographical area has been in a dry spell for a week or two, or for a shorter period, if before spring green-up or after fall color, and the National Fire Danger Rating System (NFDRS) is high to extreme and all of the following weather parameters are forecasted to be met:

- Ten-hour fuels (moisture content of small vegetation that take only about 10 hours to respond to changes in moisture conditions) of 8 percent or less
- A sustained wind average 15 mph or greater.
- Relative humidity less than or equal to 25%.
- A temperature of greater than 75 degrees Fahrenheit.

In some states, dry lightning and unstable air are criteria. A Fire Weather Watch may be issued prior to the Red Flag Warning.

Supervisory Control and Data Acquisition (SCADA): The control system architecture comprising computers, networked data communications and graphical user interfaces (GUI) for high-level process supervisory management, while also comprising other peripheral devices like programmable logic controllers (PLC) and discrete proportional-integral-derivative (PID) controllers to interface with process plant or machinery. The use of SCADA has been considered also for management and operations of project-driven-process in construction.

Strike Distance: A measurement that shows that a tree has the ability to fall into PGE's equipment, especially power lines.

Tier 1 Risk: Describes an area where there is not an elevated or extreme risk of wildfires.

Tier 2 (Elevated) Risk: Describes an area where there is an elevated risk (including likelihood and potential impacts on people and property) of utility-associated wildfires.

Tier 3 (Extreme) Risk: Describes an area where there is an extreme risk (including likelihood and potential impacts on people and property) of utility-associated wildfires.

Appendix 4. Wildfire Mitigation Plan Maintenance

The PGE Wildfire Mitigation Plan is part of the BCEM library of plans, and can be accessed electronically within the BCEM Document Library on the BCEM SharePoint site:

https://pgn4.sharepoint.com/sites/corporateresilience/SitePages/Plans.aspx

PGE's WM&R organization will review and update the Wildfire Mitigation Plan annually, by June 1. WM&R will start plan reviews by notifying individuals with planning responsibilities via email.

The nature of the edits and the required approvals includes:

- **Comprehensive**: Significant change to approach that affects structure and design of the plan. Requires new approval signature page in addition to plan owner approval on revision table.
- **Major**: Update to a specific section or content aimed at improving the plan.
- **Routine**: Update that is administrative. Examples include terms, naming conventions, and updating specific information to keep plan current.

All updates are documented on the revision table, noting who made the update and approval from the plan owner (PGE's Director, Wildfire Mitigation & Resiliency).

Rev. No.	Revision Date	Reason for Revision	Affected Pages
1	06/01/2021	Annual WMP comprehensive review and update	ALL
2	06/01/2022		
3	06/01/2023		
4	06/01/2024		

Appendix 5. Fire Season Declaration Procedure

Name of Document	Description	Document Owner	Location
Fire Season Declaration Procedure	This procedure establishes methods for declaring fire season, identified roles and responsibilities and outlines key tasks that need to be completed in association declaring fire season.	Manager, Wildfire Operations Program Management	Wildfire Mitigation Internal Vital Records SharePoint

Appendix 6. End of Fire Season Declaration Procedure

Name of Document	Description	Document Owner	Location
End of Fire Season Declaration Procedure	This procedure establishes methods for declaring an end to fire season, identified roles and responsibilities and outlines key tasks that need to be completed in association declaring fire season.	Manager, Wildfire Operations Program Management	Wildfire Mitigation Internal Vital Records SharePoint

Appendix 7. SCC Fire Risk Mitigation Procedure

Name of Document	Description	Document Owner	Location
SCC Fire Risk Mitigation Procedure	The Fire Risk Mitigation procedure provides operational guidance to PGE System Control Center (SCC) operators to reduce the risk of a fire starting as the result of a fault or operator action on PGE's transmission and distribution systems	Director, Grid Operations Manager, Grid Engineering and Compliance Manager, Transmission & Distribution Dispatch Manager, Distribution Operations	Wildfire Mitigation Internal Vital Records SharePoint

Mt Hood (Zone 1)					
Lines	**Section of the Line**	**Substations Single-Sourced**	**Substations Out of Service**	**Generation Out of Service**	**Notes**
Brightwood-Rhododendron 57kV	All	Sandy	Brightwood Rhododendron Summit Welches	Portland Hydro Project (City of Portland/EWEB)	N/A
Dunns Corner-Brightwood 57kV	All				
Dunns Corner-Portland Hydro Project 57kV	All				
Dunns Corner-Welches 57kV	All				
Rhododendron-Summit 57kV	All				

Columbia River Gorge (Zone 2)					
Lines	**Section of the Line**	**Substations Single-Sourced**	**Substations Out of Service**	**Generation Out of Service**	**Notes**
None	N/A	N/A	N/A	N/A	N/A

Oregon City (Zone 3)					
Lines	**Section of the Line**	**Substations Single-Sourced**	**Substations Out of Service**	**Generation Out of Service**	**Notes**
None	N/A	N/A	N/A	N/A	N/A

<table>
<tr><th colspan="6">Estacada (Zone 4)</th></tr>
<tr><th>Lines</th><th>Section of the Line</th><th>Substations Single-Sourced</th><th>Substations Out of Service</th><th>Generation Out of Service</th><th>Notes</th></tr>
<tr><td>Faraday-McLoughlin 115kV</td><td>Faraday-McLoughlin 115kV::Faraday-Redland Tap Section</td><td rowspan="6">Redland</td><td rowspan="6">Faraday 115kV
Oak Grove
North Fork
Lake Harriet
EWEB
Stone Creek
EWEB
Timothy Lake</td><td rowspan="6">Faraday Generator #6
Oak Grove
North Fork
Lake Harriet
Stone Creek
EWEB
Timothy Lake</td><td rowspan="6">Currently no way to sectionalize Faraday-McLoughlin 115kV and McLoughlin-Oak Grove 115kV to keep Redland substation in service. A new switch on the Faraday-McLoughlin 115 kV line will be installed on the east side of the Redland Tap in 2021, but not before the start of fire season. UNTIL THE SWITCH IS INSTALLED, OPEN JUMPERS AT THE THREE-POLE STRUCTURE D33-07B, 1467/1468/1469.

The Faraday-McLoughlin 115 kV and McLoughlin-Oak Grove 115 kV lines are in a corridor, minimizing risk, however, the lines experienced fire damage in 2020 and should be included in the PSPS.</td></tr>
<tr><td>McLoughlin-Oak Grove 115kV</td><td>All</td></tr>
<tr><td>Faraday-Oak Grove 115kV</td><td>All</td></tr>
<tr><td>Faraday-North Fork 115kV</td><td>All</td></tr>
<tr><td>Oak Grove-Lake Harriet EWEB 115kV</td><td>All</td></tr>
<tr><td></td><td></td></tr>
<tr><td>Boring-Faraday 57kV</td><td>Boring-Faraday 57kV::Faraday-SW 5720 Section</td><td>Colton
River Mill</td><td>Faraday 57kV</td><td>Faraday Generators #7</td><td>Boring loses two of its four sources</td></tr>
</table>

Faraday-River Mill 57kV	Faraday-River Mill 57kV::Faraday-SW 5723 Section			& #8 (Under Construction)	because the lines are open at Faraday
Faraday-Molalla 57kV	Faraday-Molalla 57kV::Faraday-Colton Section				

Scotts Mills (Zone 5)					
Lines	Section of the Line	Substations Single-Sourced	Substations Out of Service	Generation Out of Service	Notes
None	N/A	N/A	N/A	N/A	N/A

Portland West Hills (Zone 6)					
Lines	Section of the Line	Substations Single-Sourced	Substations Out of Service	Generation Out of Service	Notes
Sellwood-Raleigh Hills 115kV	All	Cedar Hills Multnomah Raleigh Hills Riverview Sylvan	N/A	N/A	The section of concern is along Scholls Ferry Road, which is the Raleigh Hills Tap-Sylvan Tap 115kV section. There is no way to sectionalize this part of the line.

Tualatin Mountains (Zone 7)					
Lines	Section of the Line	Substations Single-Sourced	Substations Out of Service	Generation Out of Service	Notes
None	N/A	N/A	N/A	N/A	N/A

Central Oregon					
Lines	Section of the Line	Substations Single-Sourced	Substations Out of Service	Generation Out of Service	Notes
Bethel-Round Butte 230kV	N/A	N/A	N/A	N/A	N/A

Additional Lines for Enhanced Vegetation Inspection	
Lines	**Section of the Line/Notes**
Carver-McLoughlin #1 230kV	Entire line
Carver-McLoughlin #2 230kV	Entire line
Harborton-Trojan #1 230kV	Between Harborton and approximately NW Rocky Point Rd
Horizon-St Marys-Trojan 230kV	Between approximately Germantown Rd. and NW Rocky Point Rd
Canyon-West Portland 115kV	Entire line, since alternate source to Sylvan (Sellwood-Raleigh Hills 115kV) is part of the PSPS
E-St Marys 115kV	Station E to Bethany Section
St Marys-Wacker 115kV	Entire line, since alternate source to Cedar Hills is part of the PSPS
Sellwood-Urban-West Portland 115kV	Entire line, since preferred source to Multnomah and Riverview (Sellwood-Raleigh Hills 115kV) is part of the PSPS
West Portland-Garden Home 115kV	Entire line, since preferred source to Raleigh Hills (Sellwood-Raleigh Hills

	115kV) is part of the PSPS
Boring-Dunns Corner 57kV	Entire line, since alternate source to Sandy is part of the PSPS
Boring-Faraday 57kV	Part of the line is in PSPS Zone 4
Boring-Hogan South-Lents 57kV	Boring to approximately SE Hogan Ave (3-terminal line junction point)
Boring-River Mill 57kV	Entire line, since River Mill is single-sourced in PSPS
Dunns Corner-Hogan South 57kV	Dunns Corner to Orient Section
Faraday-Molalla 57kV	Part of the line is in PSPS Zone 4, Colton single-sourced in PSPS

Appendix 8. Corporate Emergency Operations Plan (CEOP)

Name of Document	Description	Document Owner	Location
Corporate Emergency Operations Plan (CEOP)	The purpose of the CEOP is to provide a comprehensive and systematic approach to how PGE manages incident response.	Manager, Business Continuity & Emergency Management	PGE Internal BCEM SharePoint

Appendix 9. Wildfire Pocket Guide – Training & Field Reference Material

Name of Document	Description	Document Owner	Location
Wildfire Pocket Guide	This guide is a work instruction for field crews to utilize during fire season. It provides a standard communication process, educates on risk of starting and ensures that if a fire is started, employees are equipped to extinguish and escape the area safely.	Wildfire Operations Program Management	PGE Internal SharePoint

Appendix 10. Public Safety Power Shut-off (PSPS) Plan

Name of Document	Description	Document Owner	Location
Public Safety Power Shut-off (PSPS) Plan	The PSPS plan outlines how PGE will execute a PSPS including the actions taken to prepare for, respond to, and recover from a PSPS event	Business Continuity & Emergency Management Consultant	PGE Internal BCEM SharePoint

Appendix 11. Wildfire Communications & Outreach Plans

Name of Document	Description	Document Owner	Location
Wildfire Communications Plan	PGE's communications approach will cater to our eight defined audiences and to the phases of wildfire crisis. This approach ensures we are aligning our work to our customer guiding principles and delivering the right information at the right time	Senior Manager, Corporate Communications	PGE Internal SharePoint
Wildfire Outreach Plan	The Wildfire Outreach Plan provides clarity on wildfire risks and highest impacted areas for external stakeholders, a high-level outline of PGE resiliency and wildfire action plans, detailed requests for partnership to serve Oregonians, and a mechanism to solicit feedback.	Manager, Government Affairs	PGE Internal SharePoint

Appendix 12. Wildfire Protection Summary – Distribution Feeders

Name of Document	Description	Document Owner	Location
Wildfire Protection Summary – Distribution Feeders 2021	The Wildfire Protection Summary outlines the 2021 distribution feeder protection philosophy for the circuits energizing high-risk segments of overhead line in the six identified PSPS zones. The intent of the overview is to provide a clear and concise reference for how all programmable protective devices are intended to operate for normal, wildfire and red-flag periods.	Manager, Distribution Operations Engineering	PGE Internal SharePoint

Appendix 13. Agency Engagement Plan

Name of Document	Description	Document Owner	Location
Agency Engagement Plan	The Agency Engagement Plan provides a framework and process for PGE's annual wildfire-related engagement activities, including Public Safety Power Shutoff (PSPS) and reactive de-energization requests, involving external agency stakeholders: government agencies, state cooperators, Tribes and authorities having jurisdiction (AHJ).	Director, Wildfire Mitigation & Resiliency	WM&R Internal SharePoint

Appendix 14. 2021 Community Resource Center (CRC) Plan

Name of Document	Description	Document Owner	Location
Community Resource Center Plan	The Community Resource Center Plan provides a framework and process for PGE's CRC deployment activities, including site selection, external outreach, resourcing, setup, operational protocols, outreach and communications, and takedown/post-deployment activities.	Manager, WOPM	Wildfire Mitigation Internal Vital Records SharePoint

Appendix 18: 2021 PGE Damage Assessment Guide

Name of Document	Description	Document Owner	Location
Damage Assessment Guide	Performing damage assessments and restoration work in an active fire area, fire evacuation zone or burn area can be dangerous, especially when proper precautions are not taken. PGE has developed a Guide for Wildfire Damage Assessments and Operating in Fire Evacuation Zone. The product provides: • An overview Health and Safety Considerations • Guidance and considerations for performing Damage Assessments in a Burned Area • Guidance for deploying crews and working in a Fire Evacuation Zone (zones 1-3) The product is intended to support standard processes for damage assessment and crew deployment.	Manager, WOPM	PGE Internal SharePoint

Wildfire Mitigation Plan

Final Audit Report 2021-06-04

Created:	2021-06-04
By:	Elizabeth Warnell (liz.warnell@pgn.com)
Status:	Signed
Transaction ID:	CBJCHBCAABAA7jeTFGQZx5GSFmzsB0jPba1oCYO_vVK9

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2021-06-04 - 9:17:28 PM GMT- IP address: 174.204.207.136

W. M. Messner (william.messner@pgn.com) has agreed to the terms of use and to do business electronically with PORTLAND GENERAL ELECTRIC CO
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Signature Date: 2021-06-04 - 10:35:17 PM GMT - Time Source: server- IP address: 147.79.176.156

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Brad Jenkins (bradley.jenkins@pgn.com) has agreed to the terms of use and to do business electronically with PORTLAND GENERAL ELECTRIC CO
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Signature Date: 2021-06-04 - 11:00:23 PM GMT - Time Source: server- IP address: 147.79.224.154

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2021-06-04 - 11:10:22 PM GMT- IP address: 147.79.224.150

Larry Bekkedahl (larry.bekkedahl@pgn.com) has agreed to the terms of use and to do business electronically with PORTLAND GENERAL ELECTRIC CO

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Document e-signed by Larry Bekkedahl (larry.bekkedahl@pgn.com)

Signature Date: 2021-06-04 - 11:10:52 PM GMT - Time Source: server- IP address: 147.79.224.150

Agreement completed.

2021-06-04 - 11:10:52 PM GMT

Data Analysis - 2020 OPUC Audit

DISCLAIMER: This analysis was completed on **9/16/2020.** This document operates under approriate and necessary assumptions based on information and data available at the time. Any inquiry into the current status of, projected and/or real, progress of violation reconciliation by PGE Vegetation Management must include consultation by Vegetation Management Analyst and/or Forestry Management prior to any official updates and/or announcements either internally or externally.

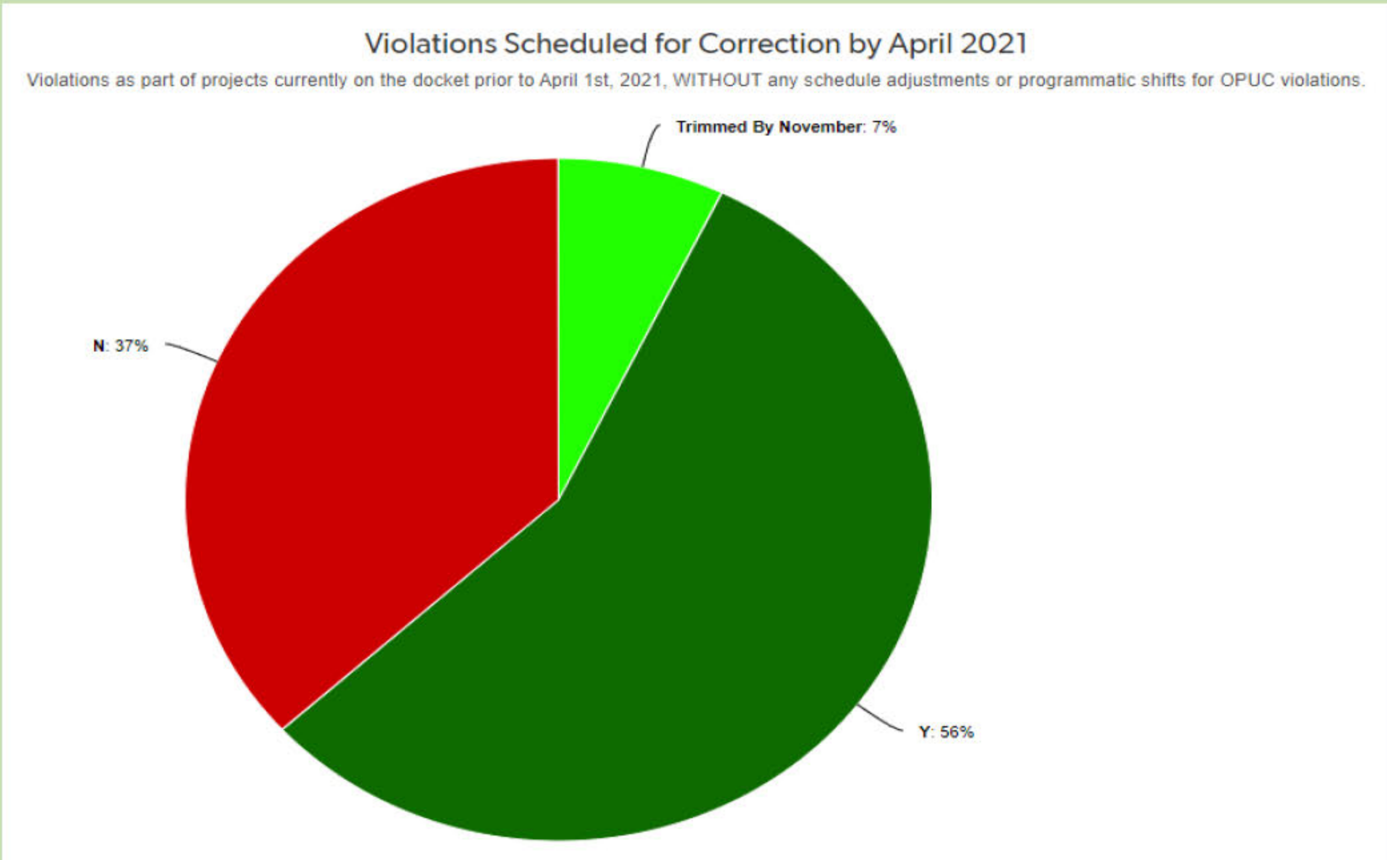
Violations: Work Progression

Total Violations:	735
*Projected Violations Corrected as of October 30th, 2020:	53
Projected Remaining Violations after November 1st, 2020:	**682**
*OPUC requires Citation A and C types (53 vios) to be corrected by 10/30/2020	

Of the **682** Violations remaining:	
Violations Scheduled for Correction **Prior to April 2021:	412
Violations Scheduled for Correction **After April 2021:	289
**Without any changes to current schedule or prioritization of OPUC violations	

Total Violations:	735	
Total Violations Corrected by April 1st 2021:	465	63%
Total Remaining Violations by April 1st 2021:	270	37%

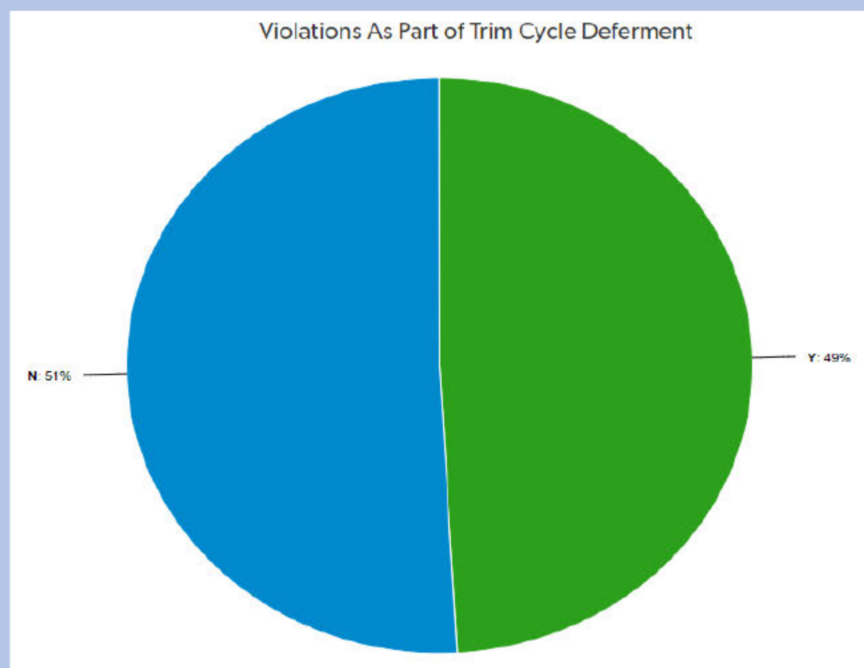
On Current Schedule (Without Adjustments):	
Q4 2020:	149
Q1 2021:	155
Q2 2021:	102
Q3 2021:	15
Q4 2021:	27
Total:	448

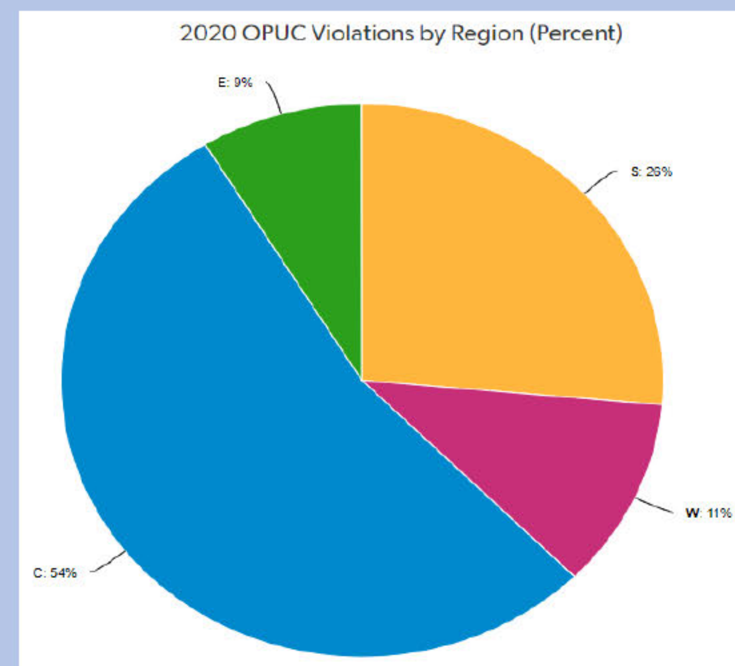


Violations: By Trim Cycle Deferment and Region

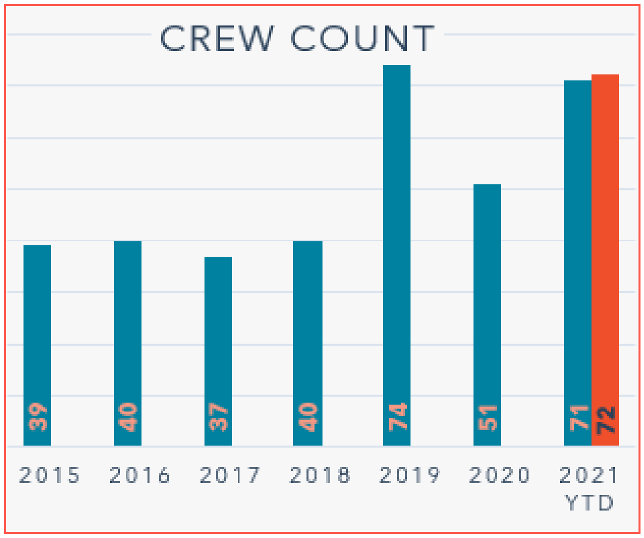
		% Tot. Vio.
Total Violations From **Deferred Map Grids**:	361	49%
Violations as part of **Deferred 2-yr Cycles**:	293	40%
Violations as part of **Deferred 3-yr Cycles**:	68	9%
Violations From **On-Schedule Map Grids**:	374	51%

Region	Violations	Percent
Eastern:	64	9%
Western:	82	11%
Southern:	194	26%
Central	395	54%





Vegetation Management Crew Count (2015 – 2021)



*Blue is local 125 crews. Orange is outsourced. 2021 is the first year that PGE has had to carry outsourced tree crews in its history.

2018 Tree Related Outages(excluding storms)

Event #	Date	Feeder	Region	Preventable	Limb contact	Cut or Felled	Broken Limb	Uprooted	Other	Total	Report
336376	1/1/18	HARBORTON-BURLINGTON	C				1				First tree crew caused outage of the year!! Cottonwood near intersection of Gillian and Reeder. Associated with outages 336288 and 336392
336308	1/2/18	SANDY-SANDY 13	NE				1				1 pole from intersection of Ten Eyck Rd and Coleman Rd. Limb on line removed by eagle.
336192	1/2/18	SANDY-SANDY 13	NE					1			OMS Tree uprooted and slapped B/C phase. Eagle re-fused and restored.
336552	1/3/18	BRIGHTWOOD-BRIGHTWOOD 13	NE					1			120' Doug Fir across the street 50' away from lines uprooted into signle phase on Sylvan RD.
336683	1/3/18	ORIENT-ORIENT 13	NE								EAST WIND EVENT 70-90mph. Broken Fir Limbs on Browers Rd. & Haines RD. Corbett, OR
337054	1/4/17	BRIGHTWOOD-BRIGHTWOOD 13	NE					1			Fuse blown @ pole 31; tree uprooted and brought down lines at 19815 E Victory Ln. between poles 872-606 off summertime Dr.
337784	1/5/18	TWILIGHT-BREMER	SE				1				Eagle reported a limb on the line. Many conifers around this location, drove out, no other apparent hazards at this time. No follow up needed.
339062	1/11/18	JENNINGS LODGE-WEBSTER	SE					1			Spruce on western and opposite side of road had root decay, uprooted, and took lines down on Rose Street. Other two stems nearby appear healthy and lean away from lines.
338562	1/11/17	SANDY-WILDCAT	NE				1				25601 SE Brian St.; D35-04D; eagle removed limb on line and restored.
339282	1/11/18	SHERIDAN-KADELL	S					1			Logger left a few oak trees across from the line that uprooted, came across road and took out wires. C56b
338201	1/9/18	DAYTON-LAFAYETTE	S					1			small fir on Abbey Rd, Lafayette - C43-6b- uprooted and took down wire, line crew repaired
339211	1/11/18	GRAND RONDE-FORTHILL	S				1				large fir limb from upper canopy took down single phase at 6900 Alvord Alley, Grand Ronde, no follow up needed.
339164	1/11/18	SCHOLLS FERRY-KEMMER	W					1			dead fir snag at 11600 Champlin Ln in c11-31d tore down primary during windy/rainy event. Line crew made all necessary repairs, no follow upo needed.
339788	1/14/18	CEDAR HILLS-SHOPPING CENTER	W				1				limb on line - primary down at 1890 SW Knollcrest in c11-02. Line crew made all necessary repairs. No follow up needed.
339925	1/14/18	CEDAR HILLS-LEAHY	W				1				not much info on this one… limb on line at 10125 NW Leahy Rd. in b11-35c. Eagles paired up to knock limb off and refused without incident
339076	1/11/18	CARVER-WOODS	NE					1			OMS said tree on line @ 16770 S. Springwater rd.. Looks like homeowner cleaned up before I could get there. No follow up
339225	1/11/18	ESTACADA-FARADAY	NE					1			Primary was down @ Pole #943 on Harvey Rd. 1 span east of Clausen Rd. from uprooted tree. Line crew removed. No follow up.
339652	1/12/18	KELLY BUTTE-MCGREW	C				1				Small Douglas fir branch on transformer at pole 11125, along fenceline of 11200 SE Holgate - Powellhurst Woods apartment complex
339779	1/14/18	FAIRVIEW-KENNEL CLUB	NE					1			East Wind (40-50+ MPH) 25" DBH Pine tree from Providence P-Lot uprooted onto 3 phase. Line crew cleared. No follow up. OMS Ref. Also # 339782,339781.
33826	1/14/18	BRIGHTWOOD-NORTHBANK	NE					1			20" DBH, 100' + Doug Fir uprooted onto single phase on Broken Bridge Rd. Fuse opened on Barlow trail Rd. bumping 57KV line. 57KV held voltage, outage only on single phase.
339802	1/14/18	WEST PORTLAND-PACIFIC	C					1			large oak in the backyard on SW 60th fell down and caused outage. Big replacement project with multiple pole replacement
340701	1/17/18	BELL-WICHITA	C			1					Private tree contractor (All Around Arbor) was trimming a birch tree and the dead top broke apart when it was being rigged out. A branch broke away and cross phased causing
341041	1/18/18	BRIGHTWOOD-BRIGHTWOOD 13	NE					1			Next door to 21100 E Country Club Rd.; 20" DBH Dpug Fir tree sitting 50' + away from lines uprooted into single phase. Tree did not knock out power. Eagle had to open fuse to
341198	1/18/18	SANDY-362ND	NE					1			Got email after hours from city of sandy in regards to tree hanging over feeder on 362nd & Skogans. Checked in with repair and they had line crew in route. Tree fell on wire before
341851	1/21/18	HARBORTON-BURLINGTON	C				1				Top of cottonwood tree a few rows back in the woods off line came from outside the right of way and hit line taking it to the ground.
341912	1/21/18	CORNELIUS-CORNELIUS 13	W				1				limb on line in c13-22c. 2 eagles paired up to knock limb off line and refuse without incident. No follow up needed. Light rain and mild winds that night..

2018 Tree Related Outages(excluding storms)

Event #	Date	Feeder	Region	Preventable	Limb contact	Cut or Felled	Broken Limb	Uprooted	Other	Total	Report	
342145	1/22/18	CEDAR HILLS-LEAHY	W	1							in b11-35c at 10255 nw lee st. between poles 2548 and 2549 local landscaper/tree trimmer cut large limb that fell onto primary opening up fuse and knocking the wire to the ground. I followed up with said landscaper the following day and did line ID and passed on our office information so he'll be sure to call us ahead in the future. Luckily, no one was hurt and the landscaper was sincere in his apology and I don't anticipate this happening again from him.	
342626	1/23/18	SCOGGINS-CHERRY GROVE	W				1				very little info from eagle.. C15-36a - cherry grove, 55432 sw lovegren dr. Removed limb and closed fuse. No other info….	
342594	1/23/18	MOLALLA-FOREST	SE				1				Eagle reported a limb had fallen on the line. After driving this out there are a few oaks and maples here with OH but there is no dead OH remaining. No follow up needed.	
342597	1/23/18	COLTON-GRAYS HILL	SE				1				Eagle reported a branch on the lines here. AT completed in 2017, drove out tap and all is now clear. Now follow up needed.	
342617	1/23/18	SCOTTS MILLS-SCOTTS MILLS 13	SE				1				only information reports "refused cutouts." This is a small single phase tap with a few trees that could have broken out. AT is 2018 but no follow up needed at this time.	I show notes from field and customer this was tree uprooted.-Gina Kent
342996	1/24/18	BORING-TELFORD	NE					1			D23-15C; Fir tree uprooted into 2 phase; actual address of uproot different than OMS: 21730 HWY 224.line crew removed and restored.	
343109	1/25/18	OSWEGO-IRON MOUNTAIN	SW				1				Eagle reported a limb on line, removed, refused. Drove out the area and the feeder and there are no more threats to the line. AT is scheduled for Q1 2018. Related to outage	
343329	1/25/18	MOLALLA-MARQUAM	SE					1			Maple with rot in the butt broke at the base and fell on lines. Maple was about 55' from the lines on the west side, about 26" DBH about 300 yards south of the intersection of Wilhoit	
343343	1/26/18	REDLAND-HENRICI	NE					1			Eagle says rotton tree uprooted onto single phase. Eagle removed tree and made repairs. 20086 Sprague Rd.	
343579	1/26/18	REDLAND-REDLAND 13	NE					1			Also OMS 343533; large white oak sitting 40'+ away from lines uprooted onto 3 pahse. Tree was removed and power was restored. On review noticed large dead fir next to	
343755	1/29/18	ORIENT-BARLOW	NE					1			Alder tree at 4625 SE Oxbow park dr. uprooted onto 2 phase. Tree fell from hill above lines. Tree removed & power restored.	
343602	1/27/18	BORING-282ND	NE					1			Rugg Rd. & 257th Dead alder snag from uphill broke off at base onto 3 phase. Repairs and power restored.	
345095	1/31/18	CENTENNIAL-BARKER	NE		1						Pole to Pole Secondary; tree branch rubbed on TX buring up wire; line crew replaced TX. Will follow up to see if additional tree trimming needed with E065. No primary	
345606	2/5/18	BRIGHTWOOD-BRIGHTWOOD 13	NE					1			Tree Uproot; E053 removed tree and re-energized tapline. D26-26A; 20875 E Country Club Rd.	
345581	2/4/18	GALES CREEK-GALES CREEK 13	W					1			uprooted alder on Soda Springs Rd., in Gales Creek tore down single phase in b14-30b between poles 846 and 847 this is just past the bridge on Soda Springs. Line crew/eagles	
345886	2/6/18	ESTACADA-FARADAY	NE					1			35572 SE Snuffin Rd. ; D34-15D; uprooted tree; eagles removed tree and restored power.	
346391	2/7/18	CANYON-CANYON 13	C			1					Spiral Tree cut limb that crossed phased and knocked out power; second contractor tree caused outage this year in Central	
347468	2/12/18	MOLALLA-FOREST	SE				1				This is recorded as a tree that fell down on the lines but was actually a limb from a fir tree near the intersection of Vaughn Rd and Hwy 211. Drove out the nearby lines and there are	
349951	2/18/18	SANDY-BLUFF	NE								Snow/wind Event; record only: broken branch on primary; Bluff Rd.	
349688	2/17/18	WELCHES-ZIG ZAG	NE								Snow/wind Event; record only: Tree took out 57KV on Henry Creek and primary below.	
350347	2/18/18	SANDY-362ND	NE								Snow/wind Event; record only: Several trees leaning onto primary from heavy snow; tickle creek; eagle removed trees and re-fused	
350516	2/19/18	EAGLE CREEK-BARTON	NE								Snow/wind Event; record only: Branch on primary; SE Jacknife Rd.	
348966	2/17/18	WELCHES-ZIG ZAG	NE								Snow/wind Event; record only: Tree uproot; took out 57KV line and primary on Henry creek Rd. related to 349000,349688	
349395	2/17/18	BRIGHTWOOD-BRIGHTWOOD 13	NE								Snow/wind Event; record only: Tree uproot on Cheryville Rd., line crew removed	
350374	2/19/18	EAGLE CREEK-RIVER MILL	NE								Snow/wind Event; record only: Removed limb off primary and re-fused	02/19/18 01:53 E048/Browning, Larry : cleared 3 trees off primary refused 25 t and held-Gina kent

2018 Tree Related Outages(excluding storms)

Event #	Date	Feeder	Region	Preventable	Limb contact	Cut or Felled	Broken Limb	Uprooted	Other	Total	Report
349000	2/18/18	WELCHES-ZIG ZAG	NE								Snow/wind Event; record only: Event related to 349668, 348996
349930	2/18/18	WELCHES-ZIG ZAG	NE								Snow/wind Event; record only: Tree uproot on RD 35; LOT 143
349273	2/17/18	SANDY-SANDY 13	NE								Snow/wind Event; record only: trees laying across rd on to 3 phase, cheryville dr.
348986	2/17/18	WELCHES-ZIG ZAG	NE								Snow/wind Event; record only: RD12 Lot 165; tree uproot
349796	2/18/18	WELCHES-ZIG ZAG	NE								Snow/wind Event; record only: RD35; 100' from HWY 26; Tree Uproot
349438	2/18/18	GALES CREEK-GALES CREEK 13	W								Snow/wind Event; record only - B14-08 - limb on line on old wilson river rd. - 12 customers affected
349543	2/18/18	TEKTRONIX-MEADOW	W								Snow/wind Event; record only - C11-09A - limb on line - no other info in OMS
349741	2/18/18	WEST UNION - CORNELIUS PASS	W								Snow/wind Event; record only - B22-14b - limb on line on NW Beck Rd. - no other info in OMS
	2/19/18	NORTH PLAINS-MASON HILL	W				1				b22-10, 20613 NW Skyline Blvd. - mild snow accumulations on this day. Eagles paired up to knock limb off line and refused without incident. No follow up needed.
351577	2/20/18	SANDY-SANDY 13	NE								Heavy Snow Event; Record Only - 40837 SE Coalman Rd., Tree branch on line from heavy snow; D25-18C
350184	2/18/18	ESTACADA-NORTH FORK	NE								Heavy Snow Event; Record Only - 38753 SE Porter Rd.; D34-36B; Tree branch on line from heavy snow
348987	2/17/18	GLENCULLEN-SUNSET	C				1				Broken limbs on dying alder tree. Will take out several trees in this area in the spring time
349791	2/18/18	SYLVAN-PATTON	C					1			Uprooted Douglas fir on wooded tap through the woods; Line needs to be reconfigured
315804	2/21/18	ESTACADA-ESTACADA 13	NE								Heavy Snow; 27599 SE Heiple Rd. & Woods Rd.; snow loaded limb burned down primary.
351841	2/21/18	ESTACADA-FARADAY	NE								Heavy Snow; Tree Uproot onto primary; 32761 SE Belfiles Rd., eagle removed tree and crew restored power
352157	2/22/18	HARBORTON-BURLINGTON	C				1				Line crew removed branch from line and restored power. NW Cornelius Pass
352196	2/22/18	BORING-282ND	NE				1				Line crew removed branch from lines and re-fused. 8099 SE Telford Rd.
353429	2/26/18	WELCHES-ZIG ZAG	NE				1				24805 E Lolo Pass Rd., Limb on line removed by eagle, re fused (Snow)
353395	2/26/18	WELCHES-ZIG ZAG	NE					1			68186 E Fairway Ave., Tree removed off line; refused cutout (Snow)
353281	2/25/18	WELCHES-ZIG ZAG	NE				1				23563 E Willwood Rd. top of tree broke out onto primary, line crew removed top and made repairs. (Snow)
353375	2/25/18	ROCKWOOD-ROCKWOOD 13	NE				1				18951 NE Flanders St.; Limb broken on primary; eagle removed and refused cutout
353293	2/25/18	SYLVAN-BARNES	W						1		in b11-36d (around skyline and cornell) at 425 NW Skyline Blvd. OMS said tree/limb burning but the operational notes don't note the tree.
	2/25/18	HARBORTON-LINNTON	C					1			cleared and no immediate follow up but it would be good to clear back similar trees along this stretch, line feeds city pumping station.
353483	2/26/18	WELCHES-WELCHES 13	NE					1			Tree uproot; 27490 E Elk Park Rd.; line crew removed tree and made repairs (Snow)
353562	2/26/18	WELCHES-WELCHES 13	NE					1			Dead Alder uprooted onto 2 phase from upper bank. knocked 1 span to ground. (Snow) 68186 E Fairway Ave. Welches
353395	2/25/18	WELCHES-WELCHES 13	NE				1				Limb on line (Snow); 68186 E Fairway Ave., eagle removed branch and re-fused.
354107	2/27/18	MOLALLA-FOREST	SE					1			lines, causing them to burn down. The tree was off ROW and on a cut-bank above the road. The location was very tenuous on the active edge of the bank. More trees are

2018 Tree Related Outages(excluding storms)

Event #	Date	Feeder	Region	Preventable	Limb contact	Cut or Felled	Broken Limb	Uprooted	Other	Total	Report
354355	3/1/18	NORTH PLAINS-NORTH PLAINS 13	W					1			Creek), tree cleared itself (must've slapped the phases together) and caused an outage for 6 customers on NW Gerrish Rd. Eagles paired up to refuse without incident.
355128	3/4/18	REDLAND-REDLAND 13	NE					1			Per Eagle; Tree uprooted @ 21500 S Horseshoe Ln., knocking primary to ground. Line crew removed tree and made repairs to restore.
355763	3/6/18	BANKS-CEDAR CANYON	W					1			through both private land and ODOT ROW. Small, dead fir uprooted onto b and c phases interrupting power for 23 people. Line crew and eagle worked together to remove said tree
356974	3/8/18	SANDY-SANDY 13	NE					1			D25-20D; Tree uprooted @ 20298 SE Verneer Ln.; line crew removed tree and made repairs.
356955	3/8/18	SANDY-WILDCAT	NE					1			D25-32C; Kona Ln. off Pagh Rd.; uprooted tree onto single phase. Crew repairs 3/4 spans of wire to restore.
356051	3/8/18	MULINO-SOUTH	SE					1			through the line. Tree was dead, most likely from root rot. More dead trees nearby but cannot hit lines. Located about 1/4 of a mile north of Union Mills Rd on Ringo Rd. No
356907	3/8/18	LELAND-CARUS	SE					1			clearcut uprooted to the north, through the main feeder lines on the opposite side of the road. On investigation, the clearcut was in late 2015/early 2016. This is the only tree to
357008	3/8/18	LELAND-CARUS	SE				1				Limb reported on line on S Burk Rd. Many douglas firs in the area, drove out the line, and no more threats. No follow up needed.
357961	3/12/18	SCOTTS MILLS-SCOTTS MILLS 13	SE				1				Eagle reported a limb on the line on Hwy 213. Drove out this section and found no further threats to the lines. No follow up needed.
359017	3/17/18	WELCHES-ZIG ZAG	NE					1			D38-17D; Rd. 35 Lot 78; uprooted tree; primary to ground. Line crew removed tree and made repairs.
360073	3/22/18	HOAN SOUTH-CLEVELAND	NE				1				OMS Eagle notes say broken limb; D13-03; 1020 SE 224th Ave, visited jobsite, found no evidence of broken limb from trees, there are some cut branches from line crew. No burnt
366022	3/22/18	GLENDOVEER-NORTHEAST	NE				1				like branch broke from approx. 20' above primary. Limb shut out feeder to sub. Eagle removed branch and restored. This feeder is on North side of Halsey.
360781	3/25/18	GLENDOVEER-13599	NE				1				According to E049; Broken branch knocked off line. Fuse tap. Off of 176th place and Glisan st. .
361929	3/29/18	PLEASANT VALLEY-SUN	NE								Record only; Went out to jobsite and looked at tree. Tree was intentionally cut by landowner. Eagle said he could not prove it. I followed up with land owner. Tree knocked
307098	4/18/18	ESTACADA-ESTACADA 13	NE					1			Uprooted Fir tree on to 2 phase. No follow up. Heiple Rd & Woods Rd.
373311	4/24/18	BRIGHTOOD-BRIGHTWOOD13	NE				1				Limb broke and landed on B & C phase. I drove out line and couldn't find any evidence.
373363	4/24/18	WELCHES-WELCHES13	NE				1				OMS says uprooted tree, couldn't find uprooted tree but found fresh broken maple branches. No follow up at this time.

2018 Tree Related Outages(excluding storms)

	Preventable	Limb Contact	Cut or Felled	Broken Limb	Uprooted	Other	Total
System	1	1	2	29	36	1	68
	1%	1%	3%	43%	53%	1%	
Region							
C	0	0	2	4	3	0	9
	0%	0%	22%	44%	33%	0%	
SW	0	0	0	1	0	0	1
	0%	0%	0%	100%	0%	0%	
W	1	0	0	5	4	1	10
	10%	0%	0%	50%	40%	10%	
NE	0	1	0	11	22	0	34
	0%	3%	0%	32%	65%	0%	
SE	0	0	0	7	5	0	12
	0%	0%	0%	58%	42%	0%	
S	0	0	0	1	2	0	3
	0%	0%	0%	33%	67%	0%	
SW	0	0	0	1	0	0	1
	0%	0%	0%	100%	0%	0%	

CITY OF MILWAUKIE

COUNCIL ORDINANCE No. 2197

AN ORDINANCE OF THE CITY OF MILWAUKIE, OREGON, AMENDING MUNICIPAL CODE CHAPTER 16.32 TREE CUTTING.

WHEREAS, on October 2, 2018, the City Council adopted the Milwaukie Climate Action Plan, which included two relevant urban forest strategies that will significantly contribute to Milwaukie's ability to adapt to the changing climate; and

WHEREAS, on March 19, 2019, the City Council adopted the 2019 Urban Forest Management Plan, which set goals and policies and identified actions that are crucial to maximizing the benefits of Milwaukie's trees and meeting Milwaukie's climate goals; and

WHEREAS, trees are considered valuable urban infrastructure that should be nurtured and protected as a community asset because of their ability to mitigate energy usage, reduce urban heat island effects, improve water quality, reduce infiltration and inflow, offer food and shading, improve public health and wellness, and support urban biodiversity.

Now, Therefore, the City of Milwaukie does ordain as follows:

Section 1. The Milwaukie Municipal Code Chapter 16.32 Tree Cutting is amended to read as shown on the attached Exhibit A.

Section 2. This ordinance will take effect immediately.

Read the first time on **11/17/2020** and moved to second reading by **5:0** vote of the City Council.

Read the second time and adopted by the City Council on **11/17/2020**.

Signed by the Mayor on **11/17/2020**.

Mark F. Gamba, Mayor

ATTEST:

Scott S. Stauffer, City Recorder

APPROVED AS TO FORM:

Justin D. Gericke, City Attorney

CHAPTER 16.32 TREE CODE

16.32.005 PURPOSE

The purpose of this chapter is to establish processes and standards that ensure the City maximizes the benefits provided by its urban forest. It is the intent of this code to establish, maintain, and increase the quantity and quality of tree cover on land owned or maintained by the City and within rights-of-way, and to ensure our urban forest is healthy, abundant, and climate resilient.

This code is designed to:

1. Foster urban forest growth to achieve 40% canopy coverage by 2040.
2. Maintain trees in a healthy condition through best management practices.
3. Manage the urban forest for a diversity of tree ages and species.
4. Manage street trees appropriately to maximize benefits and minimize hazards and conflicts with infrastructure.

16.32.010 DEFINITIONS

As used in this chapter:

"Arbor Day/Week" means a day/week designated by the City to celebrate and acknowledge the importance of trees in the urban environment.

"Arboriculture" means the practice and study of the care of trees and other woody plants in the landscape.

"City" means the City of Milwaukie.

"City Engineer" means the city engineer of the City of Milwaukie or designee.

"City Manager" means the city manager or the city manager's authorized representative or designee.

"Crown" means the area of the tree above the ground measured in mass or volume and including the trunk and branches.

"Cutting" means the felling or removal of a tree or any procedure that naturally results in the death or substantial destruction of a tree. Cutting does not include normal trimming or pruning but does include topping of trees.

"DBH" means the diameter at breast height.

"Dead tree" means a tree that is dead or has been damaged beyond repair or where not enough live tissue, green leaves, limbs, or branches exist to sustain life.

"Diameter at breast height" means the measurement of mature trees as measured at a height 4.5 feet above the mean ground level at the base of the tree. Trees existing on slopes are measured from the ground level on the lower side of the tree. If a tree splits into multiple trunks below 4.5 feet above ground level, the measurement is taken at its most narrow point below the split.

"Drip line" means the perimeter measured on the ground at the outermost crown by drawing an imaginary vertical line from the circumference of the crown, straight down to the ground below.

"Dying tree" means a tree that is diseased, infested by insects, deteriorating, or rotting, as determined by a professional certified in the appropriate field, and that cannot be saved by reasonable treatment or pruning, or a tree that must be removed to prevent the spread of infestation or disease to other trees.

"Hazardous tree" means a tree or tree part the condition or location of which presents a public safety hazard or an imminent danger of property damage as determined by an ISA Qualified Tree Risk Assessor, and such hazard or danger cannot reasonably be alleviated by treatment or pruning.

"Invasive species" means a tree, shrub, or other woody vegetation that is on the Oregon State Noxious Weed List or listed on the City of Milwaukie Invasive Tree List in the Public Works Standards.

"ISA" means the International Society of Arboriculture.

"ISA Best Management Practices" means the guidelines established by ISA for arboricultural practices for use by arborists, tree workers, and the people who employ their services.

"Major tree pruning" means the removal of over 20% of the live crown, or removal of or injury to over 15% of the root system during any 12-month period.

"Master Fee Schedule" is the schedule of City fees and charges adopted by City Council for the services provided by the City.

"Minor tree pruning" means the trimming or removal of less than 20% of any part of the branching structure of a tree in either the crown or trunk, or less than 10% of the root area during a 12-month period.

"NDA" means Neighborhood District Association.

"Noxious weed" means a terrestrial, aquatic, or marine plant designated by the State Weed Board under ORS 569.615.

"Owner" means any person who owns land, or a lessee, agent, employee, or other person acting on behalf of the owner with the owner's written consent.

"Park tree" means a tree, shrub, or other woody vegetation within a City park.

"Person" means any individual, firm, association, corporation, agency, or organization of any kind.

"Planning Director" means the planning director of the City of Milwaukie or designee.

"Public agency" means any public agency or public utility as defined in ORS 757.005, or a drainage district organized under ORS Chapter 547.

“Public tree” means a tree, shrub, or other woody vegetation on land owned or maintained by the City, but does not include a tree, shrub, or other woody vegetation in the right-of-way.

“Public Works Director” means the public works director of the City of Milwaukie or designee.

“Right-of-way” means the area between boundary lines of a public way.

“Shrub” means any plant with multiple woody stems that does not have a defined crown and does not grow taller than a height of 16 feet.

“Street tree” means a tree, shrub, or other woody vegetation on land within the right-of-way.

“Street Tree List” is the list of tree and shrub species approved by the City for planting within the right-of-way.

“Topping” means a pruning technique that cuts branches and/or the main stem of a tree to reduce its height or width.

“Tree” means any living woody plant characterized by one main stem or trunk and many branches, or a multi-stemmed trunk system with a defined crown, that will obtain a height of at least 16 feet at maturity.

“Tree Board” means the city of Milwaukie Tree Board.

“Tree Fund” means the Tree Fund as created by this chapter.

“Tree removal” means the cutting or removal of 50% or more of the crown, trunk, or root system of a plant, the uprooting or severing of the main trunk of the tree, or any act that causes, or may reasonably be expected to cause the tree to die as determined by an ISA Certified Arborist.

“Urban forest” means the trees that exist within the City.

“Urban Forester” means the Urban Forester of the City of Milwaukie, or designee.

“Urban Forest Management Plan” is the management plan adopted by City Council for the management of the City’s urban forest.

"Utility" is a public utility, business, or organization that supplies energy, gas, heat, steam, water, communications, or other services through or associated with telephone lines, cable service, and other telecommunication technologies, sewage disposal and treatment, and other operations for public service.

16.32.014 ADMINISTRATION.

A. The City Manager is authorized to administer and enforce the provisions of this chapter.

B. The City Manager is authorized to adopt procedures and forms to implement the provisions of this chapter.

C. The City Manager may delegate as needed any authority granted by this chapter to the Public Works Director, the Urban Forester, the Planning Director, the City Engineer, or such other designee as deemed appropriate by the City Manager.

16.32.015 CREATION AND ESTABLISHMENT OF THE TREE BOARD

A. Tree Board Composition

The Tree Board will consist of seven members, at least five of which must be residents of the City, one must be an ISA Certified Arborist, and all seven must be appointed by the Mayor with approval of the City Council.

B. Term of Office

The term of the seven persons appointed by the Mayor will be three years except that the term of two of the members appointed to the initial Tree Board will serve a term of only one year, and two members of the initial Tree Board will be two years. In the event that a vacancy occurs during the term of any member, their successor will be appointed for the unexpired portion of the term. Tree Board members will be limited to serving three consecutive terms.

C. Compensation

Members of the Tree Board will serve without compensation.

D. Duties and Responsibilities

The Tree Board will serve in an advisory capacity to the City Council. Its responsibilities include the following:

1. Study, investigate, develop, update, and help administer a written plan for the care, preservation, pruning, planting, replanting, removal or disposition of the Urban Forest. The plan will be presented to the City Council for approval every five years and will constitute the official Urban Forestry Management Plan for the City;

2. Provide advice to City Council on policy and regulatory issues involving trees, including climate adaptation and mitigation efforts;

3. Provide outreach and education to the community on tree-related issues and concerns;

4. Organize and facilitate the City's tree planting events and other public events involving trees and Urban Forestry education;

5. Assist City staff in preparing recommendations regarding the application, membership, and ongoing participation by the City in the Tree City USA Program;

6. Provide leadership in planning the City's Arbor Day/Week proclamation and celebration; and

7. Provide recommendations to City Council on the allocation of funds from the Tree Fund.

The Tree Board, when requested by the City Council, will consider, investigate, make findings, report, and make recommendations on any matter or question coming within the scope of its work.

E. Operation

The Tree Board will choose its own officers, make its own rules and regulations, and keep minutes of its proceedings. A majority of the members will constitute a quorum necessary for the transaction of business.

16.32.016 CREATION OF A TREE FUND

A. Establishment

A City Tree Fund is hereby established for the collection of any funds used for the purpose and intent set forth in this chapter.

B. Funding Sources

The following funding sources may be allocated to the Tree Fund:

1. Tree permit revenue;

2. Payments received in lieu of required and/or supplemental plantings;

3. Civil penalties collected pursuant to this chapter;

4. Agreed upon restoration payments or settlements in lieu of penalties;

5. Sale of trees or wood from City property;

6. Donations and grants for tree purposes;

7. Sale of seedlings by the City; and

8. Other monies allocated by City Council.

C. Funding Purposes

The Tree Board will provide recommendations to the City Council during each budget cycle for how the fund will be allocated. The City will use the Tree Fund for the following purposes:

1. Expanding, maintaining, and preserving the urban forest within the City;

2. Planting and maintaining trees within the City;

3. Establishing a public tree nursery;

4. Supporting public education related to urban forestry;

5. Assessing urban forest canopy coverage; or

6. Any other purpose related to trees, woodland protection, and enhancement as determined by the City Council.

16.32.017 TREE PLANTING ON LAND OWNED OR MAINTAINED BY THE CITY AND WITHIN THE PUBLIC RIGHT-OF-WAY

A. Species

Any tree, shrub, or other woody vegetation to be planted on land owned or maintained by the City or within the public right-of-way must be a species listed on the Street Tree List unless otherwise approved by the Urban Forester.

B. Spacing, size, and placement

The spacing, size, and placement of street trees, shrubs, and other woody vegetation must be in accordance with a permit issued by the City under this section. The City may approve special plantings designed or approved by a landscape architect or for ecological restoration projects where trees are likely to be planted at a much higher density to mimic natural conditions in forest regeneration and account for expected mortality.

C. Permit

No person may plant a street tree without first obtaining a permit from the City. A permit application must be submitted in writing or electronically on a form provided by the City. This permit is at no cost.

16.32.018 STREET AND PUBLIC TREE CARE

The City will have the right to plant, prune, maintain, and remove trees, shrubs, and other woody vegetation on land owned or maintained by the City and within the right-of-way as may be necessary to ensure public safety or that poses a risk to sewers, electric power lines, gas lines, water lines, or other public improvements, or is infested with any injurious fungus, insect, or other pest as determined by the Urban Forester. Unless otherwise exempted in this chapter, the City must obtain a permit for any activities performed under this section.

16.32.019 TREE TOPPING

No person will top any street tree, park tree, or other tree on public property. Trees severely damaged by storms or other causes, or trees existing under utility wires or other obstructions where other pruning practices are impractical, may be exempted from this section as determined by the Urban Forester.

16.32.020 PRUNING, CORNER CLEARANCE

Subject to enforcement under MMC 12.12.010, any tree, shrub, or other woody vegetation overhanging any street or right-of-way within the City must be maintained by the owner to ensure that no vegetation obstructs the right-of-way.

16.32.021 DEAD OR DISEASED TREE REMOVAL ON PRIVATE LAND

The City may require the removal of any tree, shrub, or other woody vegetation that is dead, diseased, or infested and that poses a significant risk to the public or the urban forest as determined by the Urban Forester. The City or its agents will notify the owners of such trees in writing.

Removal under this section must be completed within the time period specified in the written notice unless extended in writing by the Urban Forester. The owner must notify the City in writing when the required removal has been completed. If the owner does not remove the dead, diseased, or infested vegetation within the time period specified in the notice or any extension granted in writing by the Urban Forester, the City will have the right to remove the dead, diseased, or infested vegetation and charge the cost of removal to the owner pursuant to MMC Chapter 8.04. In cases where the owner demonstrates extreme financial hardship, the City Manager may grant a cost waiver in accordance with MMC 16.32.038.

16.32.022 REMOVAL OF STUMPS

All stumps of street trees must be removed by the adjacent property owner below the surface of the ground so that the top of the stump does not project above the surface of the ground.

16.32.023 INTERFERENCE WITH CITY

No person will prevent, delay, or interfere with the Urban Forester while they are engaged in work activities including, but not limited to, planting, cultivating, mulching, pruning, spraying, or removing any street trees, park trees, or dead, diseased, or infested trees on private land, as authorized in this chapter.

16.32.024 ARBORISTS LICENSE

All businesses doing arboricultural work within the City must have a current business license with the City, and at least one staff member who is an ISA Certified Arborist. The certified arborist must be on site for the duration of any arboricultural work being performed and is responsible for certifying that all arboricultural work is performed in accordance with ISA Best Management Practices.

16.32.026 PERMIT FOR MAJOR PRUNING OR REMOVAL OF STREET TREES OR TREES ON LAND OWNED OR MAINTAINED BY THE CITY

A. Applicability

1. No person will perform major true pruning or remove any tree in the right-of-way or on land owned or maintained by the City without first obtaining a permit issued by the City.

   a. For public trees, only the City, a public agency charged with maintaining the property, or a utility may submit a permit application.
   b. For street trees, the applicant must be the owner of the adjacent property or be authorized in writing by the owner of the adjacent property, where the tree will be pruned or removed.
   c. No person can remove a street tree without first obtaining a permit from the City. Permit approval may be conditioned upon either replacement

of the street tree with a tree listed on the Street Tree List or a requirement to pay to the City a fee as provided in the Master Fee Schedule.

2. For trees on land owned or maintained by the City, this chapter will be applied in conjunction with any applicable standards in Title 19 Zoning.

B. Permit Review Process

1. Application

A permit application must be submitted in writing or electronically on a form provided by the City and be accompanied by the correct fee as established in the Master Fee Schedule.

2. Public Notice and Permit Meeting.

Upon the filing of a permit application, the applicant must post notice of the major pruning or tree removal permit application on the property in a location that is clearly visible from the right-of-way. The applicant must mark each tree, shrub, or other woody vegetation proposed for major pruning or removal by tying or attaching orange plastic tagging tape to the vegetation. The City will provide the applicant with at least one sign containing adequate notice for posting, tagging tape, and instructions for posting the notice. The notice must state the date of posting and that a major pruning or tree removal permit application has been filed for the vegetation marked with orange plastic tagging tape. The notice must state that any person may request a meeting with the City within 14 days from the date of posting to raise questions or concerns about the proposed pruning or tree removal prior to issuance of the permit.

If a meeting is requested, it must be held within 14 days of the request. The City will consider all concerns raised at the meeting but will have final decision-making authority over issuance of the permit based on the criteria and approval standards set forth in subsection C below.

3. Declaration

The applicant will file a declaration on a form provided by the City stating that notice has been posted and that the vegetation proposed for major pruning or removal has been marked.

Once a declaration is filed with the City, the City will provide notice of the application to the appropriate NDA.

4. Exemptions from Public Notice

The following trees, shrubs, or other woody vegetation may be removed without public notice subject to the City's review of the application:

a. A tree, shrub, or other woody vegetation that is considered an unreasonable risk to the occupants of the property, the adjacent property, or the general public as determined by an ISA Certified Arborist in accordance with current ISA Tree Risk Assessment standards.
b. A tree, shrub, or other woody vegetation that is an invasive species and that is less than 8 inches in diameter at breast height.
c. A street tree or public tree that is less than 2 inches in diameter at breast height.

C. Review Criteria and Approval Standards

The City may issue the permit, deny the permit, or may issue the permit subject to conditions of approval. The City's decision will be final and valid for a period of one year after issuance unless a different time period is specified in the permit. Nothing prevents an applicant from requesting an amendment to an unexpired permit if the conditions and circumstances have changed.

1. Review Criteria

The City will not permit the major pruning or removal of a healthy, functioning street tree or public tree without a demonstration by the applicant that extraordinary circumstances exist. Maintenance or the replacement of sidewalks or curbs, removal of tree litter, or other minor inconveniences do not constitute extraordinary circumstances. Decisions regarding major pruning or removal of healthy, functioning street trees or public trees are fact specific and are made on a case-by-case basis by the Urban Forester. In determining whether extraordinary circumstances exist that warrant the major pruning or removal of a healthy tree, the Urban Forester will consider:

a. Whether the species of tree is appropriate for its location,
b. Whether the species of tree is an invasive species;
c. Whether the crown, stem, or root growth has developed in a manner that would prevent continued healthy growth or is negatively impacting other trees;
d. Whether maintenance of the tree creates an unreasonable burden for the property owner; and
e. Whether the major pruning or removal will have a negative impact on the neighborhood streetscape and any adopted historic or other applicable design guidelines.

2. Approval Standards

A permit will be issued only if the following criteria are met as determined by the Urban Forester:

a. The proposed major pruning or tree removal will be performed according to current ISA Best Management Practices and an ISA Certified Arborist will be on site for the duration of the tree work.
b. The tree, shrub, or other woody vegetation proposed for major pruning or removal meets one or more of the following criteria:

   (1) The tree, shrub, or other woody vegetation is dead or dying and cannot be saved as determined by an ISA Certified Arborist in accordance with ISA standards.
   (2) The tree, shrub, or other woody vegetation is having an adverse effect on adjacent infrastructure that cannot be mitigated by pruning, reasonable alternative construction techniques, or accepted arboricultural practices.
   (3) The tree, shrub, or other woody vegetation has sustained physical damage that will cause the vegetation to die or enter an advanced state of decline. The City may require additional documentation from an ISA Certified Arborist to demonstrate that this criterion is met.
   (4) The tree, shrub, or other woody vegetation poses an unreasonable risk to the occupants of the property, the adjacent property, or the general public, as determined by an ISA Certified Arborist in accordance with current ISA Tree Risk Assessment standards.
   (5) Major pruning or removal of the tree, shrub, or other woody vegetation is necessary to accommodate improvements in the right-of-way or on land owned or maintained by the City, and it is not practicable to modify the proposed improvements to avoid major pruning or removal.
   (6) The tree, shrub, or other woody vegetation is on the Oregon State Noxious Weed List.
   (7) The tree, shrub, or other woody vegetation is part of a stormwater management system and has grown too large to remain an effective part of the system.
c. Any approval for the removal of a healthy tree, shrub, or other woody vegetation must require the applicant to pay a fee as established in the Master Fee Schedule.

D. Performance of Permitted Work

All work performed pursuant to a permit issued by the Urban Forester must be completed within the time period specified in the permit unless a different time period is authorized in writing by the Urban Forester.

E. Replanting

The City will require replanting as a condition of permit approval for the major pruning or removal of a street tree or public tree.

1. The replanted tree must be a species included on the Street Tree List unless otherwise approved by the Urban Forester.

2. The City will consider alternative planting locations for street trees when replanting at the location of removal conflicts with surrounding infrastructure and the interference would impair the replanted tree.

   a. For street trees, replanted trees must be planted within the right-of-way fronting the property for which the permit was issued or, subject to the approval of the Urban Forester and with permission in writing from the adjacent property owner, within the right-of-way fronting the adjacent property.
   b. In lieu of replanting and subject to approval of the Urban Forester, the City can require he owner to pay a fee as established in the Master Fee Schedule.
   c. For public trees, replanted trees must be planted on the land from which the tree was removed unless a different location is approved by the Urban Forester.

3. The optimal time of year for planting is from September through November. If planting is necessary in other months, the City may condition permit approval to require extra measures to ensure survival of the newly planted tree.

16.32.028 PROGRAMMATIC PERMITS

Programmatic permits may be issued by the Urban Forester for routine public facility or utility operation, planned repair and replacement, and on-going maintenance programs on public properties and within the right-of-way. The purpose of a programmatic permit is to eliminate the need for individual permits for tree removal, pruning, or for ongoing activities that cover a wide geographic area and may include the pruning or removal of numerous public and street trees. Programmatic permits are evaluated to prevent cumulative adverse impacts to the urban forest and ensure that any permitted activities meet the goals and objectives of the Urban Forest Management Plan.

A. Application Requirements

A permit application must be submitted in writing or electronically on a form provided by the City and be accompanied by the correct fee.

B. Applicability

Programmatic permits may only be issued to a public agency or a utility as defined in this chapter.

C. Completeness

1. If the Urban Forester determines an application is incomplete, the Urban Forester will provide written notice to the applicant that describes the additional information needed.

2. The applicant must submit the additional information within 30 days from the date of the notice unless extended in writing by the Urban Forester.

3. If the applicant does not provide the additional information within 30 days from the date of the notice or any extension granted in writing by the Urban Forester, the application will be denied.

D. Notice of Complete Application

When the Urban Forester determines that the application is complete, the Urban Forester must provide written notice that the application is complete to the applicant and the Tree Board. The notice must provide instructions for how to obtain additional information about the application, comment on the application, and request notification of the Urban Forester's decision.

E. Review Criteria

The Urban Forester may approve a programmatic permit upon a determination that the following criteria are satisfied or will be satisfied with conditions:

1. The proposed activity will result in a net gain to the urban forest functions and benefits described in the purpose statement in MMC 16.32.005 considering the applicant's proposed performance measures, proposed tree planting, and other activities proposed to improve the overall health of the urban forest.

2. The applicant's proposed outreach and notification program provides adequate notice to residents, businesses, and the City prior to performing work authorized under the programmatic permit.

F. Decision

The Urban Forester must issue the permit, deny the permit, or may issue the permit subject to conditions of approval within 120 days of determining the application is complete. The Urban Forester's decision will be final and, if approved, the permit will be valid for a period of up to two years. Nothing prevents an applicant from requesting an amendment to an unexpired permit if the conditions and circumstances have changed. The Urban Forester's decision will be based on an evaluation of the application against the applicable review criteria in MMC 16.32.028 F.

G. Permit

Approved permits must include the following required information. The Urban Forester may modify the permit at any time to respond to any questions, changes in regulations, or previously unforeseen issues, provided the applicant is notified in writing.

1. Duration. The Urban Forester may approve a programmatic permit for a period of up to 2 years;

2. Geographic area covered by the permit;

3. Permitted activities and any restrictions on the method, number, type, location, or timing of activities;

4. Procedures and thresholds for providing notice to residents, businesses, and the City impacted by the performance of work under the permit;

5. Monitoring, performance tracking, and reporting requirements. The Urban Forester may prescribe rules or procedures that specify the manner in which such tracking and reporting occur; and

6. Traffic control requirements.

7. Annual Report. On the anniversary of permit issuance, the applicant must submit an annual report on a form supplied by the City detailing any work performed under the permit and any work scheduled to be performed.

8. Tree Size Limits

   a. The programmatic permit will not allow the removal of trees 6 or more inches in diameter, except as provided in this section.
   b. If an applicant requests removal of a healthy tree 6 or more inches in diameter during the period in which the programmatic permit is in effect, an opportunity for public comment will be provided in accordance with MMC 16.32.026 B.2
   c. For any request, the Urban Forester may further limit allowed tree removal in order to meet the review criteria in MMC 16.32.028 F.

9. Tree Work

All work performed under a programmatic permit must be performed in accordance with ISA Best Management Practices.

H. Revocation

The Urban Forester may revoke a programmatic permit upon a determination that the applicant has not followed the terms of the permit or is acting beyond the activities authorized by permit.

16.32.030 PERMIT AND FEE EXEMPTIONS

A. Hazardous Tree

If a tree is determined to be a hazardous tree by the Urban Forester, the City may issue an emergency removal permit. The removal will be in accordance with ISA Best Management Practices and be undertaken with the minimum necessary disturbance to eliminate the imminent danger.

B. Maintenance

A permit is not required for regular maintenance or minor tree pruning that does not require removal of over 20% of the crown, tree topping, or disturbance of more than 10% of the root system during any 12 month period.

C. Public Infrastructure Improvements

Any tree on land owned or maintained by the City which requires removal or pruning to accommodate a city public infrastructure improvement project will require a permit and must meet replanting requirements imposed by this chapter. If it is demonstrated that tree planting, establishment, and tree care-related project costs exceed the tree removal fee costs, the permit will not be subject to a removal fee.

D. Private Utility Services and Dwelling Units

If the Urban Forester determines that a tree, shrub, or other woody vegetation proposed for removal has an adverse effect on adjacent private utility services or threatens the structural integrity of a dwelling unit that cannot be mitigated by pruning, reasonable alternative construction techniques, or accepted arboricultural practices, the permit will not be subject to a removal fee.

16.32.038 LOW INCOME ASSISTANCE

To the extent that City funds are available, the City Manager may grant a property owner an exemption or a reduction in permit fees, removal fees, replanting fees and/or may provide assistance in removing a dead or diseased tree within in the right of way. Eligibility and extent of assistance will be based on a percentage of the property owner's median household income for the Portland-Vancouver-Hillsboro, OR-WA Metropolitan Statistical Area. A schedule of fee reductions and exemptions will be determined by the City Manager.

16.32.040 PENALTY

A person who removes a street tree or public tree without first obtaining the necessary permit from the City, removes a tree in violation of an approved permit, or violates a condition of an approved permit must pay a fine in an amount established in the Master Fee Schedule. Any fine imposed under this section must not be less than the cost of the permit and the associated removal fee for which a permit should have been obtained.

PORTLAND PARKS & RECREATION
Healthy Parks, Healthy Portland

Portland Parks & Recreation Urban Forestry Programmatic Permit
Portland General Electric

1.0 GOALS:

1.1 Protect, preserve, and restore the urban forest (Urban Forest Management Plan (UFMP), 2004).

1.2 Promote stewardship of the urban forest (UFMP, 2004).

1.3 Prevent cumulative adverse impacts to the urban forest and ensure that there is no reduction in tree canopy coverage over time (Title 11.45).

1.4 Improve public safety and tree canopy health.

1.5 Enhance communication with the public regarding tree pruning, removal, and planting for utilities.

2.0 TERMS AND TIMELINE OF PERMIT:

2.1 Permit duration is from the date of final signatures through June 30, 2022.
The permit must be signed and in effect before tree work is conducted.

2.2 Portland General Electric (PGE) is the responsible party for all activities in this permit and shall ensure all staff and contractors comply with the terms and conditions of this permit.

2.3 This permit applies only to tree management activities not related to site development or development projects. Separate permits are required for tree activities related to development.

2.4 This permit is issued under the authority of the City Forester in compliance with the requirements of City of Portland Title 11 Trees.

3.0 SCOPE OF WORK:

3.1 Activities shall prevent cumulative adverse impacts to the urban forest and ensure no net reduction in tree canopy coverage over time.

Urban Forestry
1900 SW 4th Ave, Suite 5000
Portland, OR 97201
Tel: (503) 823-TREE (8733) Fax: (503) 823-4493

Administration
1120 S.W. 5th Ave., Suite 1302
Portland, OR 97204
Tel: (503) 823-7529 Fax: (503) 823-6007

3.2 Activities are limited to routine and on-going vegetation management for public safety, service reliability, fire prevention, and compliance with Oregon Public Utility Commission line clearance requirements (OAR 860-024-016, Appendix C).

3.3 Activities shall support the 2004 Urban Forest Management Plan and the Portland General Electric Vegetation Clearance Policy (March 18, 2013 revision, Appendix A).

3.4 Location

Permit activity may occur in City of Portland rights-of-way along existing or proposed PGE transmission and distribution lines. Permit activity may also occur on City property (e.g. parks), PGE property (e.g. substations), and other private property. See Appendix B for a map of PGE's service area.

3.5 Pruning

a. PGE staff and contractors may prune trees to assure tree to electric conductor clearances for public safety, service reliability, fire prevention, and compliance with Oregon Public Utility Commission line clearance requirements (OAR 860-024-016, Appendix C).

   i. Only trees that encroach into the minimum clearance within a two or three year time period, depending on cycle, may be pruned. Trees may be pruned outside routine cycle for hazard mitigation.

   ii. Pruning impacts shall be as minimal as possible.

   iii. For trees pruned, no more than 25% of the crown shall be removed within an annual growing season, except in the case of hazard mitigation.

   iv. Trees shall not be topped.

b. Pruning shall be made with proper pruning cuts and sharp tools. Pruning activities shall adhere to American National Standards Institute (ANSI) *A300 Pruning Standard – Part 1*, International Society of Arboriculture *Best Management Practices: Utility Pruning of Trees*, International Society of Arboriculture *Best Management Practices: Tree Pruning*, and ANSI *Z133 Standards for Arboricultural Operations: Safety Requirements*, including any amendments or revisions.

c. All tree debris generated by tree pruning activities shall be removed from the site or stacked neatly for the property owner to dispose of. Streets and public rights-of-way shall be kept clear of debris.

d. Elm pruning requirements
In order to limit the spread of Dutch elm disease and comply with Oregon's state quarantine of elm wood, the following rules apply to the pruning of elm trees (*Ulmus* spp.):

   i. Elm trees shall not be pruned from April 15 through October 15 annually, unless pruning is necessary for public safety or system reliability.

      a. Pruning of elm trees during the state quarantine period requires prior approval from the City Forester. PGE shall submit an Inspection Request Form (Appendix G) at least 4-weeks in advance of planned pruning activity.

ii. Pruning tools shall be treated with disinfectant before and after pruning individual elm trees.

iii. All wood waste shall be chipped or taken to an approved commercial disposal site within 24 hours of cutting. PGE may ask the City to dispose of elm wood or branches resultant from work supporting the City.

3.6 Tree Crew Training and Quality Assurance

a. All tree pruning work must be completed under the supervision of an experienced Certified Arborist and Certified Utility Specialist with the International Society of Arboriculture (ISA), and/or a Registered Consulting Arborist with the American Society of Consulting Arborists (ASCA).

b. At least one member of every contract crew shall be qualified as a line-clearance tree trimmer, and will have a card certifying passage of an Electrical Hazards Awareness Program or equivalent.

c. Contractors and all personnel assigned to this work shall have the experience, required skills, training, and ANSI-approved equipment necessary to conduct the pruning work in a controlled and safe manner.

   i. PGE and its contractors shall comply with OSHA 1910.269 and all other federal and state occupational safety and health laws and regulations governing all work done under this permit.

d. At least one person on each tree crew shall be knowledgeable about the content of this permit before conducting tree pruning activities.

3.7 Public Notice

a. The property owner and/or occupant, or adjacent property owner in the case of street trees, shall be given written notification at least 15 days prior to planned tree pruning and/or maintenance activities. The notification shall be sent to all addresses with electrical service in the square mile grid where pruning activities will take place. All customers shall receive a notification letter whether they have trees on their property that need work or not. Written notification shall also be sent to the Neighborhood Association where pruning activities will take place. Urban Forestry will provide a link to the current Neighborhood Associations contact list and neighborhood boundaries.

   i. The notice shall state the following information:
      - Reason for the notice
      - The date of notice
      - The date(s) of the pruning
      - Contact information for PGE
      - The PGE logo

b. PGE shall also reach out to customers, public or private, of special concern. Individual door hangers or individualized consultation shall occur if the customer needs specific work planning or access to their backyard is required. When the tree crew arrives on site, they shall knock on the door of the resident to discuss any issues that may be present.

i. The Bureau of Environmental Services (BES) Watershed Revegetation Program Manager shall be contacted at least 15 days in advance of pruning trees located in stormwater management facilities. Urban Forestry will provide contact information for the BES Watershed Revegetation Program Manager.

c. Contractors and staff shall identify themselves and the fact that they are pruning for PGE either through signs displayed on each vehicle involved in tree work or verbally when requested by the public. Contractors shall provide contact information for their company and for PGE to the public upon request.

d. PGE and Contractors shall keep a copy of this permit on-hand when performing work under the purview of this permit and provide this permit to the public upon request.

e. PGE shall respond to all concerns and complaints about PGE's and their contractors' pruning activities in a timely manner.

i. Customers may be directed to PGE's Vegetation Management Operations Coordinators (VMOC) at 503-736-5460 to discuss any issues or concerns regarding PGE's line clearance work. The VMOC may also coordinate any necessary tree work for residents, private tree contractors, or municipal tree workers who plan on working on trees near power lines.

3.8 Removal

a. Unregulated trees

i. Trees in the City right-of-way (i.e. street trees) that are sucker shoots or self-sown trees less than 1/2 inch DBH (diameter at breast height, the diameter of the trunk measured at 4.5 feet above the ground) are not regulated and therefore may be removed without prior notice to Urban Forestry, reporting, or mitigation. All other street trees of any size are regulated.

ii. Trees on City property (i.e. City trees) of any size are regulated by this permit.

iii. Trees on private property that are less than 12 inches DBH are not regulated and therefore may be removed without prior notice to Urban Forestry, reporting, or mitigation, unless they were required to be planted as the condition of a permit or otherwise specified in 3.7.a.iii.a below.

a. The regulatory threshold for tree removal on private property decreases to 6 inches DBH for trees located in the following plan districts and/or overlay zones:
   - Plan districts: Cascade Station/Portland International Center Plan District; Columbia South Shore Plan District; Johnson Creek Basin Plan District; Portland International Airport Plan District; Rocky Butte Plan District; South Auditorium Plan District
   - Overlay zones: Environmental (c, p); Greenway (n, q, g, i, r); Pleasant Valley Natural Resources (v); Scenic Resource (s)

b. The property owner's permission should be obtained via signature before removing any tree on private property.

b. Dangerous trees

i. As per Title 11.80.020, a dangerous tree presents a foreseeable danger of inflicting damage that cannot be alleviated by treatment or pruning. A tree may be dangerous because it is likely to injure people or damage vehicles, structures, or development, such as sidewalks or utilities.

ii. Removal of a dangerous tree:

a. Non-Emergency tree removal requests shall be requested at least 4 weeks in advance of the anticipated removal timeframe using the Inspection Request Form (Appendix G). City Forester may approve removal of dangerous trees on a case-by-case basis. The City Forester may approve or deny the removal request or approve the removal with conditions.

b. Emergency tree removal shall be conducted as follows, as per Title 11.40.020.D: If the condition or location of a tree presents such a clear and present danger to a structure or the public that there is insufficient time to obtain advance approval of the City Forester, the hazardous portion of the tree may be removed without first obtaining approval from the City Forester.

i. Within seven days of an emergency tree removal, PGE shall provide notification and documentation to the City Forester on the Inspection Request Form (Appendix G) provided by Urban Forestry. Upon submittal to the City Forester, the Inspection Request Form shall accompany photographs or other documentation that prove an emergency existed. The City Forester will evaluate the information to determine whether the tree was dangerous. Failure to provide information documenting the emergency nature of the event may be pursued as a violation per Title 11.70.

iii. PGE must notify the adjacent property owner of the need to remove danger trees in accordance with ORS 758.282-284.

c. Non-dangerous trees

i. Street and City trees

a. Infill trees, i.e. self-sown trees that were not deliberately planted, that are 2 inches DBH or smaller may be removed without prior notice to Urban Forestry, reporting, or mitigation.

b. The City Forester may approve the removal of other non-dangerous street and City trees on a case-by-case basis. Removal may be granted if the tree is dead, or if it was planted inappropriately underneath electric conductors and requires frequent, severe pruning. Removal shall be requested at least 4 weeks in advance of the anticipated removal timeframe using the Inspection Request Form (Appendix G). The City Forester may approve or deny the removal request or approve the removal with conditions. Mitigation (see 3.7.f) and reporting (see 3.7.g) requirements apply.

ii. Private property trees

a. PGE shall obtain property owner permission, via signature, to remove the tree prior to removing any regulated trees on private property.

b. The City Forester may approve the removal of non-dangerous, regulated private property trees (see 3.7.a.iii) on a case-by-case basis. Removal may be granted if the tree is dead, or if it was planted inappropriately underneath electric conductors and requires frequent, severe pruning. Removal shall be requested at least 4 weeks in advance of the anticipated removal timeframe using the Inspection Request Form (Appendix G). The City Forester may approve or deny the removal request or approve the removal with conditions. Mitigation (see 3.7.f) and reporting (see 3.7.g) requirements apply.

iii. Zoning code exemption requirements

a. The zoning of the property (or adjacent property, for street trees) shall be checked before any non-dangerous tree is removed. Zoning information can be found on Portland Maps at www.portlandmaps.com -> maps -> zoning.

b. Trees located in the following plan districts and overlay zones shall meet zoning exemptions for removal, or else a zoning code review from the Bureau of Development Services (503-823-7526) shall be obtained prior to removal.
- Plan districts: Cascade Station/Portland International Center Plan district; Columbia South Shore Plan District; Johnson Creek Basin Plan District; Portland International Airport Plan District; Rocky Butte Plan District; South Auditorium Plan District
- Overlay zones: Environmental (c, p); Greenway (n, q, g, i, r); Pleasant Valley Natural Resources (v); Scenic Resource (s)

c. Zoning code exemption requirements are detailed in Title 11 Table 40-1 (Appendix D). Generally, a zoning code review is required for the removal of healthy native trees. However, some plan districts and overlay zones require a zoning code review for certain non-native, non-nuisance tree removals. The City Forester can help determine whether exemption requirements are met or whether a zoning code review is necessary.

d. Debris

i. All tree debris generated by tree removal activities shall be removed from the site or stacked neatly for the property owner or adjacent property owner to dispose of. Streets and public rights-of-way shall be kept clear of debris.

e. Public notice

i. The public shall be notified at least two weeks in advance of the impending removal of healthy (i.e. not dead, dying, or dangerous), non-nuisance trees 20 inches DBH or greater by posting a sign (Appendix H) on or near the tree, in a location visible to public passersby.

ii. The sign shall state when and why the tree is being removed, it is a permitted tree removal, how the removal is being mitigated, and contact information for the PGE representative the public can contact regarding the removal.

f. Mitigation

i. Title 11.45.040.A. requires activities conducted under a Programmatic Permit will result in a net gain to urban forest functions and benefits.

ii. To comply with this condition, trees that are removed under this permit shall be mitigated as follows:

a. Removed dead, dying, or dangerous trees, as defined by Title 11, shall be mitigated tree-for-tree.

b. Removed healthy trees shall be mitigated as follows:

Removed Tree DBH	Street and City Tree Mitigation	Private Tree Mitigation
< 12"	Tree-for-tree	No mitigation required
12" - < 20"	Tree-for-tree	Tree-for-tree
20" or greater	Inch-for-inch	Inch-for-inch

iii. PGE shall submit a planting plan to the City Forester for approval prior to planting.

iv. Mitigation trees shall be planted by the next planting season (October to April) immediately following removal.

v. Mitigation trees shall be planted on the same site as the removed tree wherever possible. When onsite mitigation is not possible, PGE shall document the reason in their annual quantitative report and shall instead plant mitigation trees elsewhere within the City of Portland.

vi. Trees planted for mitigation shall be monitored and guaranteed for three years and replaced in kind if they die within this timeframe.

i. Mitigation unable to be met by tree planting shall be paid into the Tree Planting and Preservation Fund. Payment for each tree to be mitigated shall be the Fee in Lieu of Planting and Establishment for two inches per Title 11 Trees Permit Fee Schedule. Mitigation payment shall be completed by the expiration of the permit.

g. Reporting

i. The number, species, and DBH of trees removed under this permit shall be reported, as well as the condition of the trees, reason for removal, and type of mitigation.

ii. The amount of money paid to the Tree Planting and Preservation Fund shall be reported.

iii. The number, species, stock size, and location of trees planted as mitigation shall be reported.

3.9 Planting

a. Planting activities shall adhere to American National Standards Institute (ANSI) A300 *Planting and Transplanting Standards* and International Society of Arboriculture *Best Management Practices: Tree Planting.*

b. The locations of trees planted in the City right-of-way (i.e. street trees) shall be approved by the City Forester.

c. Species selection

   i. Street trees (trees in the City right-of-way) selected for planting shall be selected from the City's Approved Street Tree Planting Lists (www.portlandoregon.gov/trees/plantinglists) or approved by the City Forester.

   ii. Trees planted under high-voltage power lines should be small- or medium-sized trees that can fully develop and mature to provide long-term leaf surface area under power line conductors, supporting the concept of "right tree, right place." Trees planted under high-voltage power lines should be able to maintain their natural form without pruning away from high-voltage wires.

   iii. Tree species selected for planting in environmental (c, p) or scenic (s) overlay zones shall be chosen from the Portland Plant List's Native Plants List.

   iv. Trees on the Portland Plant List's Nuisance Plants List shall not be planted.

   v. Species diversity requirements for trees planted per site

      a. When planting fewer than 8 trees per site per calendar year, they may all be the same species.

      b. When planting between 8 and 24 trees per site per calendar year, no more than 40 percent of the total planted shall be of one species.

      c. When planting more than 24 trees per site per calendar year, no more than 24 percent of the total planted shall be of one species.

d. Trees shall be a minimum of 2 inches caliper for broadleaf trees or at least 5 feet in height for coniferous trees at the time of planting.

e. Plantings shall be monitored for establishment and guaranteed for three years and replaced in kind if they fail within this timeframe.

f. The number, species, stock size, and location of trees planted shall be reported.

4.0 COMMUNICATION:

4.1 PGE shall maintain accurate permit contact information with Urban Forestry.

4.2 PGE Contact

Chad Burns, Senior Forester (Central)
Mailing address: 3700 SE 17th Ave, Portland, OR 97204
Phone: 503-849-2589
Email: chad.burns@pgn.com

4.3 PGE Representative

Alex Konopka, Vegetation Manager
Mailing address: 9480 SW Boeckman Rd, Wilsonville OR 97070
Phone: 503-570-4406
Email: Alex.konopka@pgn.com

5.0 QUALITY CONTROL AND REPORTING:

5.1 Notification

PGE shall provide the City Forester written notification of planned tree pruning locations and contractors at least 15 days prior to the activities. The notification shall include:

- Contractor company name
- Contractor business license number
- Contractor phone number, email address, and mailing address
- Map of pruning area
- Dates of pruning the area

5.2 Reporting

A qualitative and quantitative reports shall be sent to Urban Forestry once per fiscal year for the duration of the permit on forms provided by Urban Forestry (see Appendix E and Appendix F). The completed forms shall be received no later than one month after the reporting period. Failure to submit reports may result in suspension of current programmatic permit or delayed issuance of future programmatic permits until the report is submitted.

a. Reporting periods:
July 1, 2019 – June 30, 2020 report due by: August 1, 2020
July 1, 2020 – June 30, 2021 report due by: August 1, 2021
July 1, 2021 – June 30, 2022 report due by: August 1, 2022

5.3 Inspections

Urban Forestry may inspect the trees to determine compliance with the conditions of the permit.

5.4 Compliance

a. It is the permit holder's responsibility to adhere to the terms of the permit. If the terms of the permit are not met, the permit holder shall be notified of the violation in writing and informed of the actions necessary to correct the violation and the timeframe for correcting the violation.

b. If corrective actions are not undertaken within the specified timeframe detailed in the notice of violation, Urban Forestry may take one or more of the following actions:
   - Temporary stop work order

- Revocation of the Programmatic Permit
- Denial of future Programmatic Permits
- Additional conditions imposed upon the activities permitted by the Programmatic Permit
- Enforcement penalties
- Civil penalties up to $1000 per tree per day of violation
- Restoration fees imposed for trees found in violation.

c. Fees shall follow the adopted Title 11 fee schedule at www.portlandoregon.gov/trees/fees.

5.5 Revisions

Urban Forestry may modify the specifications of the permit for their behalf or at the request of PGE in order to respond to concerns, changes in regulations, or previously unforeseen issues. The permittee shall be notified at least three weeks in advance in writing of the intent to modify the permit and shall be provided an opportunity to comment on the proposed changes. The permittee shall also have an opportunity to appeal the permit if changes are made. Changes shall not go into effect until the permit is updated in writing and signed by the City Forester.

6.0 INDEMNITY:

PGE shall hold harmless, defend, and indemnify the City of Portland, and the City's officers, agents, and employees against all claims, demands, actions, and suits (including all attorney's fees and cost, through trial and on appeal) brought against any of them arising from activities under this permit. PGE shall indemnify, defend and hold the City, its officers, agents and employees, harmless from any third-party claim for injury, damage, loss, liability, cost or expense, including court and appeal costs and attorney fees or expenses, arising from any casualty or accident to person or property by reason of any activities under this Permit, by or for PGE, its agents or employees, but not if arising out of or by reason of any negligence or willful misconduct by the City, its officers, agents or employees. The City shall provide PGE with prompt notice of any such claim which PGE shall defend with counsel of its own choosing and no settlement or compromise of any such claim will be done by the City without the prior written approval of PGE. PGE and its agents, contractors and others shall consult and cooperate with the City while conducting its defense of the City.

7.0 RESOURCES:

ANSI A300 (Part 1)-2008 Pruning: Tree Care Operations: Tree, Shrub, and Other Woody Plant Management: Standard Practices (Pruning). Revision of ANSI A300 (Part 1)-2001. 2008. American National Standards Institute, Washington, DC.

ANSI A300 (Part 6)-2012: Tree Care Operations: Tree, Shrub, and Other Woody Plant Management: Standard Practices (Planting and Transplanting). Revision of ANSI A300 (Part 6)-2005. 2012. American National

ANSI Z133-2012 for Arboricultural Operations: Safety Requirements. 2012. American National Standards Institute, Washington, DC.

Gilman, Edward and Sharon Lilly. *Best Management Practices: Tree Pruning, Second Edition.* 2008. International Society of Arboriculture, Champaign, Il.

Kempter, Geoffrey. *Best Management Practices: Utility Pruning of Trees: Special companion publication to the ANSI A300 Part 1: Tree, Shrub, and Other Woody Plant Maintenance—Standard Practices, Pruning.* 2004. International Society of Arboriculture, Champaign, Il.

Watson, Gary. *Best Management Practices: Tree Planting, Second Edition*. 2014. International Society of Arboriculture, Champaign, Il.

8.0 APPENDICES:

Appendix A – PGE vegetation clearance policy 2013

Appendix B – PGE service territory

Appendix C – OAR 860.024

Appendix D – Title 11 Table 40-1 Tree Removal in Overlay Zones and Plan Districts

Appendix E – Qualitative report template

Appendix F – Quantitative report template

Appendix G – Inspection Request Form

Appendix G – Public Notice

9.0 SIGNATURE:

By: ______________________ Date: 2/27/2020

Jenn Cairo
City Forester

2008 - 2021 Actual Level III Storm Damage Losses

CPI	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
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	2.14%	2.14%	2.14%	2.14%	2.14%	2.14%	2.14%	2.14%	2.14%	$ 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	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	$ -	
2021	2.28%	2.28%	2.28%	2.28%	2.28%	2.28%	2.28%	2.28%	2.28%	2.28%	2.28%	2.28%	2.28%	$ 71,500,165
2022	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%
2022 $	$ 7,421,854	$ 2,642,239	$ -	$ -	$ -	$ -	$ 6,394,048	$ 5,862,253	$ 5,001,065	$ 12,463,363	$ -	$ 1,865,654	$ -	$ 72,867,118

Ten Year Total Level III Storm Damage Losses	$ 104,453,502
Ten Year Avg Level III Storm Damage Losses	$ 10,445,350
Average Level III Storm Damage Losses	$ 17,408,917

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	2.14%
2018	$ -	2.44%
2019	$ 1,772,198	1.81%
2020	$ -	1.00%
2021	$ 71,500,165	2.28%
2022		1.91%

	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	$ (785,476)
2016	$ 2,000,000	$ 4,504,081	$ (3,289,557)
2017	$ 2,000,000	$ 11,351,424	$ (12,640,981)
2018	$ 2,600,000	$ -	$ (10,040,981)
2019	$ 3,804,696	$ 1,772,198	$ (8,008,483)
2020	$ 3,804,696	$ -	$ (4,203,787)

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Jardon Jaramillo
Jaki Ferchland
Bente Villadsen, Ph.D.

July 9, 2021

Table of Contents

I. Introduction

Q. Please state your names and positions.

A. My name is Jardon Jaramillo. I am the Senior Director of Treasury, Investor Relations, and Risk Management at Portland General Electric Company (PGE). I am responsible for analyzing PGE's cost of capital and managing the company's treasury function including financing.

My name is Jaki Ferchland. I am the Manager of Revenue Requirement in Regulatory Affairs at PGE. I am responsible for analyzing PGE's cost of capital.

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 May 1, 2022.

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 recommend PGE's authorized cost of capital and capital structure for the 2022 test year. PGE's cost of capital and capital structure were last approved in Order No. 18-464 in December 2018.

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 2022, and to provide PGE the opportunity to earn a fair return for equity 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.

Q. What is PGE's requested overall cost of capital for this filing?

A. We request and support a 6.938% cost of capital for the 2022 test year. This cost of capital reflects PGE's currently authorized return on equity (ROE) of 9.50%, its currently authorized capital structure of 50% debt and 50% equity, and an updated long-term cost of debt of 4.375%.

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 2022 regulatory capital structure.

Table 1
PGE's Weighted Cost of Capital
Test Year 2022

Component	Average Outstanding ($000) [1]	Percent of Capital [2]	Component Cost	Weighted Cost
Long-term Debt	$3,223,174	50%	4.375%	2.188%
Common Equity	$2,830,105	50%	9.500%	4.750%
Total	**$6,053,279**	**100%**		**6.938%**

[1] "Average Outstanding" reflects PGE's projected average values of long-term debt and common equity for 2022.

[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. Did PGE issue debt as a result of the energy trading losses in 2020?

A. The energy trading losses resulted in a cash need for the company, which was met with the debt issuance completed in the fourth quarter of 2020.

Q. Does your requested regulatory capital structure include impacts from debt issuances associated with the energy trading losses?

[1] Bluefield Water Works v. Public Service Comm'n - 262 U.S. 679 (1923).
[2] FPC v. Hope Nat. Gas Co. - 320 U.S. 591 (1944).

A. No. PGE's requested regulatory capital structure does not include impacts from debt issuances completed in the fourth quarter of 2020. This is discussed in more detail in Section VI of this testimony.

Q. How is the remainder of your testimony organized?

A. In the following section, we describe PGE's financial goals and how PGE manages counterparty risks and liquidity.

- Section III provides a review of financial and market regulation changes as well as the recent and near-future financial market and economic conditions;
- Section IV discusses PGE's cost of long-term debt, including new and redeemed issuances;
- Section V provides the updated analysis that supports maintaining PGE's ROE at its current level of 9.50%;
- Section VI discusses PGE's capital structure; and
- Section VII provides our qualifications.

II. PGE's Financial Goals

Q. What is PGE's overall financial goal?

A. PGE's overall goal is to provide adequate capital and liquidity to fund PGE operations at the least cost and least risk to customers. Aligned with this goal is protection against unforeseen negative changes in cash flows and managing daily cash and liquidity needs. For these goals, PGE relies on its revolving lines of credit, long-term debt, and common equity.

Q. Does PGE have additional financial goals?

A. Yes. PGE's overall financial goals include financial performance, counterparty credit risk management, and liquidity management:

- Solid financial performance including:
  - 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.
- Managing wholesale counterparty and retail customer credit risks to protect our customers and PGE.

- Liquidity Management to meet our obligations and support PGE's operations.

A. Solid Financial Performance

Q. Why is it important for PGE to maintain an investment grade credit rating?

A. It is important for PGE to maintain an investment grade credit rating in order to secure financing for both debt and equity at reasonable rates, especially in today's changing financial environment, and to maintain access to wholesale energy markets with the best prices for customers. 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. Fundamentally, PGE's credit rating is a function of its financial performance, which is driven by PGE's 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 costs to finance operations through the optimal use of revolving credit line, long-term debt, and equity, closely monitoring capital structure; and analyzing counterparty risks and taking appropriate mitigation measures. Using all of these measures helps PGE maintain financial performance levels necessary for investment grade credit ratings.

Q. Financial performance is an important element for the rating agencies. Do rating agencies also consider other factors?

A. Yes. Other factors that rating agencies consider include regulatory and recovery risk, corporate operations and growth, customer and portfolio diversification, and liquidity and other financial measures. We note that in prior years, the rating agencies have been concerned 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. The rating agencies also continue to 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. PGE closely monitors the evolving rating agencies' methodologies and annually visits the major rating agencies for presentations and discussions.

Q. Have PGE's bond ratings changed recently?

A. The most recent change in PGE's rating occurred in July 2018 when Standard & Poor's (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. Yes. S&P changed the outlook for PGE from Positive to Negative following the announcement of energy trading losses in August 2020. S&P revised its outlook for PGE to stable in January 2021 following the conclusion of the review conducted by the Special Committee of the board of directors.

Q. How does PGE ensure an optimal long-term cost of capital?

A. PGE aims to issue long-term debt so that debt maturity schedules closely match the investment schedules of its capital projects. PGE prefers First Mortgage Bonds (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. 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's financial performance impact its desired long-term capital structure?

A. Yes. As we stated earlier, 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. In 2020, PGE's financial performance was impacted by higher power costs associated with energy trading losses. As stated above, the energy trading losses resulted in a cash need for the company, which was met with the debt issuance completed in the fourth quarter of 2020 which impacted PGE's accounting capital structure.

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, and cash from operations to help maintain PGE's desired capital structure.

B. Manage 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 2020, PGE's customers were impacted by restrictions put in place to limit the spread of COVID-19. To mitigate the effect on customers, in March 2020, PGE initiated a voluntary suspension of disconnecting customers for non-payment and the imposition of late fees on past due bills. For small commercial customers, these activities resumed in December 2020, and for residential customers, this extends into August 2021[3]. The moratorium has resulted in a significant increase in residential and commercial arrearages and uncollectible customer payments[4]. PGE serves some of the hardest hit industries including transportation, retail, restaurants, and recreation.

Q. Has PGE experienced an increase in customer bankruptcies as a result of COVID-19?

A. PGE did not experience a significant increase in large customer bankruptcies as a result of

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[3] Order No. 21-164, Docket No. UM 2114.

[4] As of March 31, 2021, PGE's deferred balance for its COVID-19 deferral was $10 million, comprised primarily of bad debt expense in excess of what is currently considered in customer prices. PGE expects bad debt expense to be $6 million to $8 million for the year-ended 2021.

COVID-19. The biggest negative impact was felt by smaller commercial accounts that faced changing demand and operational challenges. PGE also anticipates experiencing a number of residential bankruptcies and inability to pay by residential customers as we continue to recover from the economic impacts associated with COVID-19.

Q. How does PGE manage its customer credit risk exposure?

A. For nonresidential 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 customers to minimize loss in the event of a default.

PGE performs credit reviews of its customers, particularly large customers, and associated industries annually. Other items, such as negative company and industry news, a public debt rating downgrade, or consistent late payment trends with PGE may trigger a credit review. PGE's load forecasters work closely with its Key Customer Managers to gain a better understanding of the 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. 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 revolver 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 June 2021.

Q. What were the results of that analysis?

A. After a preliminary benchmark analysis of our peer's revolving credit facilities, PGE determined that it is currently below median on all prevailing credit ratios. As a general principle, a company's revolving credit facility should be one times EBITDA, which would necessitate PGE to increase its current facility to $650 million.

PGE will continue to monitor the need to increase the revolver in future years.

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 their rating criteria. Based on this analysis, PGE determined that a revolver capacity of $650 million would be sufficient at this time to service the company's short-term financing needs.

III. Uncertainty in Regulation, Accounting, and Financial Markets

A. Regulation and Financial Markets

Q. What are PGE's current bond ratings?

A. PGE's current bond ratings for secured (first mortgage) long-term debt are A1 from Moody's and A from S&P. Ratings for unsecured debts are A3 and BBB+. PGE's credit ratings, which were recently affirmed, are provided in PGE Exhibit 902.

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. Moody's places 25% weight on the factor "Regulatory Framework."[5] S&P indicates that "[r]egulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness."[6] Key characteristics in the assessment of 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. Have financial analysts or rating agencies noted any concerns regarding regulatory mechanisms for PGE?

A. Yes. Financial analysts have expressed concerns regarding the company's PCAM. PGE's asymmetrical deadband is unique. Most electric utilities tend to have a 'pass through' of their

[5] With the other three factors and their weights being "Ability to Recover Costs and Earn Returns," 25%, "Diversification," 10%, and "Financial Strength and Liquidity," 40%. "Rating Methodology – Regulated Electric and Gas Utilities." Moody's Investor Service- December 23, 2013.
[6] "Key Credit Factors for the Regulated Utilities Industry." Standard & Poor's- November 19, 2013.

power costs if a PCAM is in place, with no deadbands. Thus, it is not unexpected that analysts have expressed concerns about PGE's wide deadband and the asymmetry of benefits allocation, which could result in "meaningful" impacts on PGE's earnings, increasing volatility. Wolfe Research sees the PCAM as a source of earnings volatility that contributes to a valuation discount to the peer group: "We raise our [price target]… which still reflects a 10% discount to our group average given structural lag and earnings volatility due to the PCAM."[7] Wells Fargo mentions the following risks for PGE: negative regulatory developments, risks related to the asymmetrical PCAM (hydro, plant outages, etc.), and lower than expected sales growth/higher than expected expense inflation.[8] Bank of America lists the PCAM as a "downside risk".[9] Goldman Sachs views the mechanism as currently constructed to be a source of incremental risk: "unlike most utilities which can pass through all fuel/purchase power costs, POR's authorized power cost adjustment mechanism (PCAM) only allows for a limited pass-through of costs within an established band, creating incremental risk for the company."[10]

Q. What concerns have financial analysts expressed regarding the decoupling mechanism?

A. Most electric utilities do not have a cap on their uncollected revenues associated with decreased energy use per customer. Analysts have expressed concerns about PGE's 2% cap, which has impacted PGE's earnings in 2020 and will continue to impact PGE's earnings in 2021, increasing earnings volatility. Wolfe Research mentions: "POR's decoupling mechanism only covers residential and commercial for moves of up to 2%; POR expects to

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[7] "Been POR enough; upgrade" – Wolfe Research – 16 July, 2020.
[8] "POR Solid Q3 Update – Investigation Into Trading Losses Ongoing" – Wells Fargo – 30 October, 2020.
[9] "Could this be the inflection in sentiment?" – Bank of America – 2 November, 2020.
[10] "Portland General Electric Co. (POR): Material power management impact to pressure 2020 results; Sell" Goldman Sachs – 25 August 2020.

breach that threshold to the downside for commercial but remain under to the upside for residential (POR would have to refund if resi went above 2%). POR trailed the UTY by 460bps following the update. We have maintained our U/P rating in the past, citing POR's EPS volatility relative to peers".[11] Goldman Sachs views the mechanism as an "unfavorable demand recovery structure that offsets the benefits of robust residential electric usage in the current environment."[12] Guggenheim views the current construction of the mechanism as a "unique challenge": "This presents a unique challenge as the residential growth is decoupled, while only the first 2% of commercial is recovered."[13]

Q. How does increased earnings volatility impact PGE's cost of capital?

A. Financial theory states that, all else equal, increased earnings volatility results in increased uncertainty or risk and thus, a higher return to investors. This is because investors and creditors require greater compensation for owning an investment with more risk. All else equal, a firm with greater earnings volatility will have a higher cost of capital than a firm with more stable earnings. If the current PCAM structure results in a higher level of earnings volatility relative to that faced by comparable firms, then investors' required rate of return for PGE will be higher as well. As a result, investors will demand a higher return to hold PGE's debt or common stock, which will increase the cost to finance PGE activities.

B. Update of Financial and Accounting Regulation Changes

Q. What challenges does PGE face in connection to FASB[14] pronouncements?

A. Accounting Standards Codification (ASC) 810 Consolidation of Variable Interest Entities

[11] "Earnings lock down" – Wolfe Research – 26 April, 2020
[12] "Portland General Electric Co. (POR): Key takeaways from virtual management meetings" – Goldman Sachs – 16 August, 2020.
[13] "POR – Return to Normalcy? Not Quite but Portland Managing Through" – Guggenheim Securities – 31 July, 2020.
[14] Financial Accounting Standards Board (FASB)

(VIE), provides guidance for determining the financial reporting for entities over which control is attained by means other than through voting rights. Under ASC 810, consolidation is based on the power to direct significant activities of the VIE and the obligation to absorb losses that are significant to the VIE. The entity with the power to direct significant activities and the obligation to absorb significant losses becomes the "primary beneficiary" of the VIE and, in turn, is required to consolidate the financial statement of the VIE for financial reporting to the Securities and Exchange Commission (SEC). ASC 810 requires consolidated financial statements to reflect total assets under control and total liabilities for which an entity is responsible.

Under ASC 810, although it is not involved in the creation of these entities and has no equity or debt invested, PGE may be required to reflect the total assets, liabilities, and non-controlling interests of its PPA counterparties on PGE's balance sheet on an ongoing basis when reporting its financial position on a consolidated basis. Some of the counter-party entities are expected to be highly debt leveraged and consolidating their capital structure will likely increase PGE's debt-to-equity capital structure. This high debt leverage will impact PGE's creditworthiness, as the increase to PGE's debt-to-equity percentage increases financial risk.

Q. Has the FASB revised or added Accounting Standards that could impact PGE?

A. On January 1, 2019, PGE adopted Accounting Standards Codification (ASC) Topic 842, which supersedes the previous lease accounting requirements for lessees and lessors within Topic 840, Leases. Among other requirements, lessees are required to recognize all leases, including operating leases, on the balance sheet and record corresponding right-of-use assets and lease liabilities. Accounting for lessors is substantially unchanged from prior accounting principles. Lessees are required to classify leases as either finance leases or operating leases. Initial balance sheet measurement is similar for both types of leases; however, expense recognition and amortization of right-of-use assets will differ. Operating leases will reflect lease expense on a straight-line basis, while finance leases will result in the separate presentation of interest expense on the lease liability (as calculated using the effective interest method) and amortization expense of the right-of-use asset.

Q. How did this change impact financial results?

A. Upon adoption of the new standard on January 1, 2019, PGE recognized right-of-use assets and liabilities on its balance sheet from operating and finance leases of $44 million.

Q. Does this change how costs related to leases are recovered from customers?

A. No. Cost recovery methods have not changed from ASC 840 to ASC 842. PGE has historically recovered its costs related to leases via recovery of lease payments, either through general rate cases or other mechanisms, such as the Annual Update Tariff (AUT). Leased assets have not been included in rate base historically.

Q. How do the rating agencies view this change to PGE's financial reporting?

A. The rating agencies consider operating and finance leases to be debt which poses a constraint on PGE's ability to borrow. With the adoption of ASC 842 the rating agencies no longer need to impute the lease amount and can now directly reclassify the lease liability on the balance sheet as debt. Moody's and S&P made adjustments, adding all of PGE's lease liabilities to the Company's outstanding long-term and short-term debt to come up with a final adjusted debt amount. As a result, this impacts our key credit ratios including FFO/Debt (S&P) and CFO Pre-WC/Debt (Moody's).

Q. What challenges does PGE face in connection with imputed debt??

A. PGE faces significant risks and uncertainties connected with imputed debt from purchased power 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. A ratings downgrade by S&P from PGE's current rating level could result in higher interest rates on debt issuances, an inability to attract equity capital at a reasonable price, and additional collateral postings for power supply operations.

IV. Cost of Long-Term Debt

Q. What is PGE's cost of long-term debt?

A. PGE's cost of long-term debt in 2022 is expected to be 4.375%. PGE Exhibit 901 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 June 30, 2021, as well as other bond issuances expected in 2021 and 2022.

Q. How did you calculate the cost of long-term debt for 2022?

A. We included the applicable adjustments to debt as approved in OPUC Order No. 18-464 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)

	2022 Forecast
Principal Amount	$3,306,508
Annual Interest Cost	$144,664
Effective Interest Rate	**4.375%**

Q. What future debt issuances did you include in your analysis?

A. We expect to issue up to $400 million in long-term fixed rate debt during 2021 and $100 million in long-term fixed rate debt during 2022 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 2021 and 2022?

A. PGE currently expects to issue a 30-year tranche of FMBs in 2021 with a coupon rate of 3.90%. This tranche is expected to be funded during the fourth quarter of 2021. PGE currently expects to issue a 30-year tranche of FMBs in 2022 with a coupon rate of 4.22%. This tranche is expected to be funded during the fourth quarter of 2022. 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 *Global Insight*.

Q. Is there any long-term PGE debt maturing in 2021 or 2022?

A. Yes. PGE has $160 million of term loans maturing in 2021. There are no scheduled maturities in 2022.

Q. Did PGE issue any long-term debt following the energy trading losses?

A. PGE issued two tranches of FMBs for a total for $230 million following the energy trading losses. The process to issue these FMBs had not started until after PGE's announcement of the trading loss.

Q. How has PGE treated the amounts associated with the energy trading losses in its calculation of long-term debt?

A. The $127 million of debt issued in Q4 of 2020 associated with the energy trading losses, net of taxes, were removed from PGE's cost of long-term debt calculation, as PGE has elected not to include any costs associated with the energy trading loses in this rate case.

V. Cost of Equity

Q. Please summarize your results regarding the ROE.

A. I, Bente Villadsen, recommend that PGE be allowed to earn the requested ROE of 9.5 percent on the equity portion of its regulated rate base at the requested 50% equity capital structure. I consider that recommendation conservative and it is based on my finding that the estimated range for an electric utility sample's cost of equity is in the range of 8.5% to 10¾% and supported by data estimated for natural gas and water utilities. Within that range, I find a ROE in the range of 9.5 to 10.25 percent is the most appropriate as that is the average low and high of my electric utility sample results, respectively. The natural gas and water utilities support that range. The recommendation is based on my implementation of standard cost of capital estimation models including two versions each of the Discounted Cash Flow (DCF) model and the Capital Asset Pricing Model (CAPM), as well as an Implied Risk Premium analysis as well as an analysis of PGE's business risk. Table 3 below summarizes the model results using the requested 50% equity capital structure.

I recognize that the Public Utility Commission of Oregon in the past has favored the DCF method and in particular the multi-stage DCF model. However, the results from the multi-stage DCF are substantially lower than those from other models (e.g., the CAPM and risk premium) and also much lower than the ROE allowed electric utilities across the country.[15] Plausibly, the COVID-19 pandemic severely impacted the economy in general and therefore a contemporaneous measure of expected growth may not reflect the conditions going forward, which would result in a downward biased ROE result.[16]

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[15] According to S&P Global Intelligence the average allowed ROE for 2021 year-to-date (as of June 9, 2021) was 9.47%.

[16] The difference between the results from the multi-stage DCF model and those of other models has increased over the past year.

Table 3
Summary of Reasonable Ranges of Estimates at 50% Equity

	Electric Sample	
	Low	High
CAPM*	9.8%	10.7%
ECAPM*	9.9%	10.7%
Multi-Stage DCF	8.4%	
Single-Stage DCF		10.1%
Risk Premium	9.8%	9.8%
Range	8.4%	10.7%
Average, all method:	9.5%	10.3%

* Ignores the constant ATWACC approach

Because the multi-stage DCF under estimates the cost of equity at this time, I find a reasonable range to consider for electric utilities before any company-specific risk factors are considered to be 9 ½% to 10 ¼ % ROE at the 50% equity.[17] This range was determined as the average of relied upon methods rounded to the nearest ¼ percent.

In the current environment electric utilities are facing substantial changes longer term and challenging load and cost recovery due to the COVID-19 period. Specifically, moratoriums on disconnections, such as that in place in Oregon,[18] have resulted in larger uncollectable balances and therefore currently lower cash flow to the utility. Hence, the circumstances are not as in the past for which reason, I find it beneficial to confirm the estimates for other regulated industries and to that end I selected a sample of highly regulated gas and water utilities. These regulated industries confirm the low end of the recommended range and indicates a higher upper end for the ROE. Thus, results within the electric sample range are conservative. A summary of these results is presented below in Table 4.

[17] The CAPM / ECAPM range above ignores results from the constant ATWACC approach as Commission staff in the past has taken issue with the method and is thus conservative as those figures indicate a higher ROE.
[18] Oregon's moratorium on disconnections was recently extended to June 30, 2021. Source: Oregon utility regulators extend disconnection moratorium to June 30 - KTVZ

Table 4
Summary Results for Natural Gas and Water Utilities

	Gas & Water		Gas Sample		Water Sample	
	Low	High	Low	High	Low	High
CAPM*	9.8%	11.0%	9.9%	10.9%	9.8%	11.0%
ECAPM*	9.8%	10.9%	9.9%	10.9%	9.8%	10.9%
Multi-Stage DCF	7.8%		8.5%		7.1%	
Single-Stage DCF		10.9%		11.0%		10.9%
Range	7.8%	11.0%	8.5%	11.0%	7.1%	11.0%
Average, all methods	9.2%	10.9%	9.4%	10.9%	8.9%	10.9%

* Ignores the constant ATWACC approach

The results in Table 4 span a wider range than the electric ROE estimates but are consistent with the results and therefore confirm that the electric utility sample range is reasonable.

Q. Do you have any preliminary comments regarding the appropriate ROE?

A. Yes. The current determination of PGE's allowed ROE takes place during the ongoing uncertainty in economic and financial conditions due to the ongoing impacts of the COVID-19 pandemic, which has led to unprecedented low U.S. Treasury bond yields and substantial volatility in stock and commodity price. Although risk-free rates have increased and market volatility has declined, the risk premium that investors require to hold equity rather than government bonds remain elevated. Going forward, the length and extent of the impacts of the pandemic are not known and will depend on how measures impacting commerce stay in place and how fast the effects of the COVID-19 pandemic dissipate.[19] More recently, concerns regarding inflation and risks of inflation have come to light – for example, the Consumer Price Index, a common measure of inflation, increased by 4.2% from April 2020

[19] I acknowledge that all of society has been impacted to a degree not seen in decades, but I focus my discussion on the financial and economic impacts in this report. I also note that most states have recently reopened the economy.

to April 2021 – the largest 12-month increase since September 2008.[20]

In light of this uncertainty, it is important to assure investors that the allowed ROE and capital structure is such that PGE can continue to raise the needed capital to continue to provide service to its customers, while also providing a return that is comparable to those investors expect. To that end, I note that the average allowed ROE for natural gas utilities in 2021 year to date was 9.6% on an average of 51% equity.[21]

Q. How is the remainder of your testimony 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 capital markets and their impacts on the cost of capital. Section C explains my analyses and presents the results. Section D discusses PGE's business risk characteristics that are relevant to my recommended allowed ROE and concludes with a summary of my recommendations.

A. Cost of Capital Principles and Approach

Risk and the Cost of Capital

Q. How is the "Cost of Capital" defined?

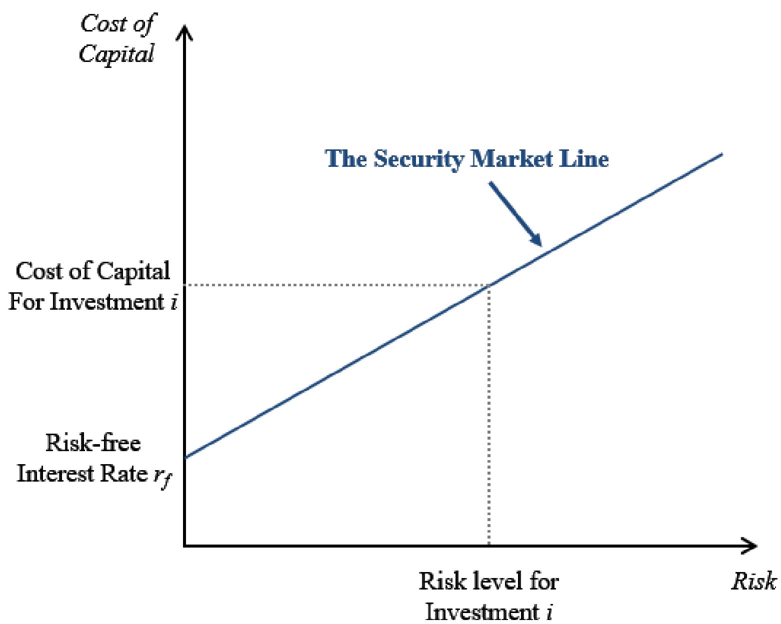
A. The cost of capital is defined as the expected rate of return in capital markets on alternative investments of equivalent risk. Put differently, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type 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

[20] U.S. Bureau of Labor Statistics, "Consumer Price Index up 4.2% from April 2020 to April 2021," May 19, 2021, accessed May 24, 2021, https://www.bls.gov/opub/ted/2021/consumer-price-index-up-4-2-percent-from-april-2020-to-april-2021.htm.
[21] S&P Global Intelligence as of June 4, 2021.

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. This Security Market Line is depicted below. The higher the risk, the higher the 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 context of the CAPM, business risk can be quantified in terms of an "asset beta" or "unlevered beta." For a company with an asset beta of 1, the value of its enterprise will increase (decrease) by 1% for a 1% increase (decline) in the market index.

The second category of risk relevant for an 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 standards that define a just and reasonable allowed rate of return on rate-regulated utility investments?

A. The seminal guidance on this topic was provided by the U.S. Supreme Court in the *Hope* and *Bluefield* cases,[22] which found that:

- The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks;[23]
- 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.[24]

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

[22] Bluefield Water Works & Improvement Co. v. Public Service Com'n of West Virginia, 262 U.S. 679 (1923)("Bluefield"), and Federal Power Com'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope").
[23] Hope, 320 U.S. at 603.
[24] Bluefield, 262 U.S. at 680.

aligned with the financial concept of the opportunity cost of capital.[25] The cost of capital is the rate of return investors can expect to earn in capital markets on alternative investments of equivalent risk.[26]

By investing in a regulated utility asset, investors are tying up some capital in that investment, thereby foregoing alternative investment opportunities. Hence, the investors are incurring an "opportunity cost" equal to the returns available on those alternative investments. The allowed return on equity needs to be at least as high as the expected return offered by alternative investments of equivalent risk or investors will choose these alternatives instead. If it is not, the utility's ability to raise capital and fund its operations will be negatively impacted. This is a fundamental concept in cost of capital proceedings for regulated utilities, such as PGE.

Q. Please summarize how you considered risk when estimating the cost of capital.

A. To evaluate comparable business risk, I looked to a proxy group of regulated electric utilities and supported the analysis by similar calculations for natural gas and water utilities. The electric utilities I consider have a high proportion of regulated assets and revenue, with the majority having more than 80% of assets subject to regulation and the remainder having at least 50% subject to regulation. Additionally, they all have a network of assets that are used to serve end-use customers and they are capital intensive (meaning that each dollar in revenue requires substantial investment in fixed assets). Like PGE the majority own electric distribution, generation, and transmission. The natural gas and water utilities are similarly

[25] A formal link between the opportunity cost of capital as defined by financial economics and the proper expected rate of return for utilities was developed by Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases," Bell Journal of Economics & Management Science 3:58-97 (1972).
[26] 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).

highly regulated and serve a mixture of customers through a network of fixed assets. However, because they do not provide electric service, I ensure my recommendation is fully supported by the electric sample. Further (as explained in Section B below), I analyzed and adjusted for differences in financial risk due to different levels of financial leverage among the proxy companies and between the capital structures of the proxy companies and also between the capital structures of the proxy companies and the regulatory capital structure that will be applied to PGE for ratemaking purposes. To determine where the estimated range of PGE's ROE reasonably falls, I compared the business risk of PGE to that of the proxy companies.

Financial Risk and the Cost of Equity

Q. How does capital structure affect the cost of equity?

A. Debtholders in a company have a fixed claim on the assets of the company and are paid prior to the company's owners (equity holders) who hold the inherently variable residual claim on the company's operating cash flows. Because equity holders only receive the profit that is left over after the fixed debt payments are made, higher degrees of debt in the capital structure amplify the variability in the expected rate of return earned by equity-holders. This phenomenon of debt resulting in financial leverage for equity holders means that, all else equal, a greater proportion of debt in the capital structure increases risk for equity holders, causing them to require a higher rate of return on their equity investment, even for an equivalent level of underlying business risk. This fact has been clearly acknowledged in the Commission Staff's calculations of the cost of equity for utilities, which in the past has relied on a version of the Hamada method.[27]

[27] See, for example, direct testimony of Matt Muldoon in UE 294, p. 15.

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 in turn is applied to the regulatory equity portion of PGE's rate base. Because the cost of equity is measured using a group of proxy companies, it may well be the case that these companies finance their operations with a different debt and equity proportion than the proportion the Commission allows in PGE's capital structure. 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 that 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 the 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.[28] 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 percent 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 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 percent equity financed firm to obtain a so-called all-

[28] The impact of financial leverage on the risk premium model needs to be considered separately as it uses regulatory data rather than market data, meaning that differences in regulatory capital structures are relevant for this model. As PGE's requested capital structure is very close to that of the average electric utility that has had a rate case decided in recent years, I make no adjustments for financial leverage in this model.

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. This is the approach that previously has been taken by Commission Staff. In Exhibit 905, I set forth additional technical details regarding the methods that can be used to account for financial risk when estimating the cost of capital. This approach is well recognized and described in standard finance textbooks.

Q. Can you provide a numerical illustration of how the cost of equity changes, all else being 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%. 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 split between equity and debt holders. This principle is illustrated in Figure 2 below.

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] × 8%	$80.0	$80.0
Cost of Debt (5%)	[e] = [c] × 5%	$25.0	$27.5
Equity Return	[f] = [d] - [e]	$55.0	$52.5
Rate of Return on Equity (ROE)	**[g] = [f] / [b]**	**11.00%**	**11.67%**

Figure 2 above illustrates how financial risk[29] affects returns and the ROE. The overall return remains the same for Company A and B at $80. But 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 increased risk to equity investors caused by the higher degree of leverage.

The principle illustrated in Figure 2 is an example of the first adjustment I perform 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 I am comparing apples to apples. However, because the allowed ROE, which is used in the risk premium model, usually is applied to book value capital structures, it is the book value capital structure that is relevant for the risk premium method. Further, the average book value capital structure for electric utilities for which I have allowed ROE data for, the past has been close to that of PGE, so I do not need to make any adjustments to the estimated ROE. I note that for 2020 and 2021 year-to-date the average allowed equity percentage were 49.7 and 49.2 percent, respectively.[30] Thus, comparable to that requested by PGE.

Approach to Estimating the Cost of Equity

Q. Please describe your approach for 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

[29] 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.
[30] S&P Global Market Intelligence assessed June 4, 2021.

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. Because certain models require market data, my considerations of comparable companies is restricted to those that have publicly traded stocks. To this end, I have selected a proxy group consisting of publicly traded electric utilities. These are listed as publicly traded electric utilities by Value Line and have the majority of their assets subject to regulation with most having in excess of 80 percent regulated assets.[31] I also consider a group of natural gas distribution and water utilities to assess the reasonableness of the results and my recommendation. I rely on standard financial models to estimate the cost of equity, including two versions of the DCF as preferred by Commission Staff in the past. As economic conditions currently are very uncertain, I consider it necessary to also consider other estimates from the CAPM and risk premium-based models.

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) interest rate developments; (ii) investors perception of the market

[31] I consider a natural gas distribution utility sample and a sample including water utilities in addition to the electric sample. The latter samples have the advantage of being highly regulated and, like electric utilities are engaged in distributing a commodity through an extensive network of fixed assets. My recommendation, however, is fully supported by the electric sample.

risk premium, (iii) federal stimulus to the economy, and (iv) inflation risks and the impact on cost of equity.

Q. Why do you discuss capital market conditions in a 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. Inputs to the DCF model are affected by the economy in general, as economic growth will affect growth rates and utility stock prices. Consequently, the capital market developments affect the growth rates, dividend yields, and the assessment of estimates' reasonableness.

Furthermore, the risk-free rate is an input to the risk premium and CAPM. Therefore, 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 Risk Premium (MRP) is an input to the CAPM, so factors that affect the MRP (e.g. volatility and changes in investors' risk perceptions) are vital for accurate determination of the ROE. Federal stimulus plausibly will impact the economy's growth rate, interest rates as well as inflation and are therefore important for ROE determination. Lastly, as the cost of equity is determined in nominal terms, an increase in the inflation rate will impact the cost of equity – even if the real cost of equity remains constant.

Q. Can you provide a summary of recent events that have impacted capital market conditions?

A. Over the past year, capital markets experienced unprecedented levels of uncertainty due to the impacts of the COVID-19 pandemic on the global economy. Following the formal pandemic declaration by the World Health Organization in March 2020, governments around the world sought to limit the health and economic impacts from the outbreak. States issued stay-at-home orders and major portions of the U.S. economy shut down. This also led to a significant rise in unemployment with over 77 million people filing initial unemployment claims since March 21, 2020.[32]

To mitigate the economic impact, the U.S. Federal Reserve cut its policy rate to 0 to 0.25 percent and announced "unlimited" quantitative easing and emergency liquidity programs.[33] The U.S. also passed the $2.1 trillion CARES Act, which provided direct aid to people and businesses and also bolstered unemployment benefits. Despite these efforts, the U.S. economy contracted substantially and by June 2020 the U.S. entered a recession.[34] In the 1st and 2nd Quarter of 2020, real GDP decreased by an annualized rate of 5.0% and 31.4%, respectively.[35]

More recently, the U.S. government has passed a $1.7 trillion American Rescue Plan, which similarly is intended to stimulate the U.S. economy.[36] These efforts have added about $1.5 trillion to the U.S. economy to date and the federal deficit reached a higher level than at any time since World War II at the end of 2020.[37] The level of federal spending and need to finance the deficit has created some fears of inflation. For example, Obama's former economic advisor and Harvard professor, Lawrence Summers, has warned that "*the trillions*

[32] U.S. Department of Labor, "Unemployment Insurance Weekly Claims," New Release, December 10, 2020. Data, accessed March 2, 2021, https://oui.doleta.gov/unemploy/claims.asp.
[33] U.S. Federal Reserve, "Federal Reserve Announces Extensive New Measures to Support the Economy," Press Release, March 23, 2020.
[34] National Bureau of Economic Research, "Determination of the February 2020 Peak in US Economic Activity," June 8, 2020, accessed September 21, 2020, https://www.nber.org/cycles/june2020.html.
[35] Bureau of Economic Analysis, "Gross Domestic Product, 2nd Quarter 2020 (Third Estimate); Corporate Profits, (Revised)", U.S. Department of Commerce, September 30, 2020. Accessed October 2, 2020, https://www.bea.gov/news/2020/gross-domestic-product-third-estimate-corporate-profits-revised-and-gdp-industry-annual.
[36] See, for example, Senate passes Biden's $1.9 trillion relief package including $1,400 stimulus checks (yahoo.com)
[37] See Exhibit BV-xx for details.

of dollars Biden wanted to spend could create "'inflationary pressures of a kind we have not seen in a generation.' "[38] Professor Summers' concerns are consistent with recent inflation concerns expressed in Bank of America's recent Fund Manager Survey, where inflation topped the list of managers concerns.[39]

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 the value of any allowed ROE being reduced. Thus, with the risk of inflation increasing, there is an increased risk that the allowed ROE will be downward biased within a relatively short time, e.g., a year

Economic condition improved in the second half of 2020 and the first few months of 2021. In the 3rd and 4th Quarter, real GDP increased by an annualized rate of 33.4% and 4.1%, respectively.[40] Also, in Q1, 2021, preliminary estimates is that the economy grew at an annualized rate of 6.4 percent.[41] Despite the rebound, recent employment figures have been disappointing.[42] The Federal Reserve also remains cautious about the pace and extent of the recovery. In December 2020, the Federal Reserve reiterated "Economic activity and employment have continued to recover but remain well below their levels at the beginning of the year," and "the ongoing public health crisis will continue to weigh on economic activity, employment, and inflation in the near term, and poses considerable risk to the economic

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[38] Lydia Moynihan, New York Post, "Larry Summers raises inflation concerns as he blasts Biden's spending," May 17, 2021.
[39] CNBC, "Investors now fear inflation more than COVID, Bank of America Survey shows," March 16, 2021.
[40] Bureau of Economic Analysis, "Gross Domestic Product, Fourth Quarter and Year 2020 (Second Estimate)", U.S. Department of Commerce, February 25, 2021. Accessed March 2, 2021, https://www.bea.gov/news/2021/gross-domestic-product-fourth-quarter-and-year-2020-second-estimate.
[41] Gross Domestic Product, 1st Quarter 2021 (Second Estimate); Corporate Profits, 1st Quarter 2021 (Preliminary Estimate) | U.S. Bureau of Economic Analysis (BEA)
[42] May's Jobs Report Misses Expectations as Signs of Labor Shortage Peek Through | Barron's (barrons.com)

outlook over the medium term."[43] The Federal Reserve has kept its policy interest rate at 0 to 0.25 percent and is also continues to support financial markets through its expanded quantitative easing programs.[44]

While the length and extent of the economic impacts from the COVID-19 pandemic are unknown, the impacts are expected to persist for some time.

Q. What are the expectations going forward?

A. The impacts on the economy and unemployment will depend on how long the economy remains partially shut down, but the economy is expected to continue to recover in mid-2021 based on recent forecasts. Recent survey by economist, such as the Blue Chip Economic Indicators (BCEI) survey, indicate that U.S. real GDP will increase by 5.7% in 2021 and 4.1% in 2022 for a nominal GDP at about 8 and 6 percent, respectively.[45] In August, the U.S. Federal Reserve announced a policy change whereby they would target inflation of 2% on average, noting that the Federal Reserve would hold overnight borrowing interest rates lower for longer.[46] Recent projections from the FOMC clarified that policy rates will remain at current levels through at least 2023.[47] This will likely continue to exert downward pressure on interest rates over the near to medium term although the impact of inflation pressures has yet to be seen.

Q. How does this impact the cost of equity estimation for PGE?

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[43] Board of Governors of the Federal Reserve System, "Federal Reserve issues FOMC statement," December 16, 2020, https://www.federalreserve.gov/newsevents/pressreleases/monetary20201216a.htm.
[44] Ibid.
[45] Wolters Kluwer Blue Chip Economic Indicators and PwC Analysis, February 2021, p. 2-3
[46] U.S. Federal Reserve, "Federal Open Market Committee announces approval of updates to its Statement on Longer-Run Goals and Monetary Policy Strategy," August 27, 2020, accessed March 2, 2021, https://www.federalreserve.gov/newsevents/pressreleases/monetary20200827a.htm.
[47] U.S. Federal Reserve, "March 17, 2021: FOMC Projections materials, accessible version," March 17, 2020, https://www.federalreserve.gov/monetarypolicy/fomcprojtabl20210317.htm.

A. It is important to remember that the cost of equity and capital structure established for PGE in this proceeding is expected to be in effect beyond the current extraordinary impacts of the COVID-19 pandemic. The analysis and recommendations should reflect expected market conditions that will prevail over the relevant rate period and not exclusively current market conditions. As discussed further below, many of the inputs to the cost of equity estimation methodologies are currently at unprecedented levels. Sole reliance on current economic and financial conditions to estimate PGE's cost of equity would unfairly lock PGE and their customers into the current economic and financial environment. Doing so would also not provide a fair return, especially when compared to other utilities that did not undergo a cost of capital proceeding during this period. However, the current conditions create an exorbitant amount of uncertainty about the future and, if the financial crisis can be used as a guide, investors' heighted perception of risk are likely to linger.

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 (see Figure 3). 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 depressed due to economic uncertainties related to COVID-19 or the monetary policy responses, using current yields as the risk-free rate will depress the CAPM estimate below what is representative of the forward-looking cost of equity, which will be in effect during the relevant regulatory period. Put differently, with current government bond yields downwardly biased due to flight-to-quality behavior by investors and "unlimited" quantitative easing programs by the U.S. Federal Reserve, using current yields in the CAPM will also downward bias the cost of equity estimate. At the same time, a low interest rate is associated with a high market risk premium, so that these two measures offset one another to a degree. To avoid any bias in the cost of equity estimate, it is important to use a forecasted risk-free rate and consider whether the rate needs to be normalized (or the risk premium investors require needs to be adjusted) to ensure the resulting CAPM estimate reflects a non-biased estimate of PGE's cost of equity over the relevant regulatory period. As the economy begins to recover, as forecasted, interest rates are expected to increase from current levels.[48] Therefore, the allowed fair return on equity for utilities should reflect the future interest rate environment.

Q. What are the relevant developments regarding interest rates?

A. Current interest rates remain low with the 10-year government bond yield standing at 1.65% as of April 30, 2021, despite significant improvement since the historic low levels in 2020. Interest rates on 10-year U.S. Government bonds were at 1.86% at the end of 2019.[49] As large parts of the economy began to shut down in response to the pandemic, investors fled riskier assets for safer assets. This demand for U.S. government bonds caused bond yields to decrease rapidly. On March 9, 2020, the entire U.S. yield curve fell below 100 bps for the first time in history and the 10-year U.S. government bond yield hit a record low of 0.339%.[50] Since then, the U.S. government bond yields have risen – perhaps in the light of the recent

[48] The 10-year treasury bond yield has increased more than 50 basis points from the summer of 2020; for example, the yield was 0.55% on August 6, 2020 but stood at 1.63% on March 17, 2021
[49] Bloomberg accessed October 23, 2020 and Federal Reserve; FRED assessed December 3, 2020
[50] Sunny Oh, "Treasury yield curve sinks below 1% after oil and coronavirus worries rout stocks," Market Watch, March 9, 2020, accessed March 31, 2020, https://www.marketwatch.com/story/30-year-treasury-yield-tumbles-below-1-after-oil-and-coronavirus-worries-rout-stocks-2020-03-09

reopening of the economy – but still remain near historic lows and below end of 2019 levels. The current 10-year U.S. Government bond yield is approximately 1.65.[51]

Looking forward, treasury bonds are forecasted to increase, which is depicted in 3 below. BCEI March and May 2021 edition forecasts that the yield on 10-year treasury bonds will increase. Specifically, BCEI projects the 10-year government bond yield will be 2.1, 2.3 and 2.5 percent in 2022, 2023 and 2024, respectively (see Figure 5).[52] The expectations for the period after January 1, 2022 is what is relevant for this proceeding as rates are going into effect in 2022 and remain for a period. Because the risk-free rates is an input to several cost of equity estimation models, the relationship between current and forecasted risk-free rates is an important consideration.

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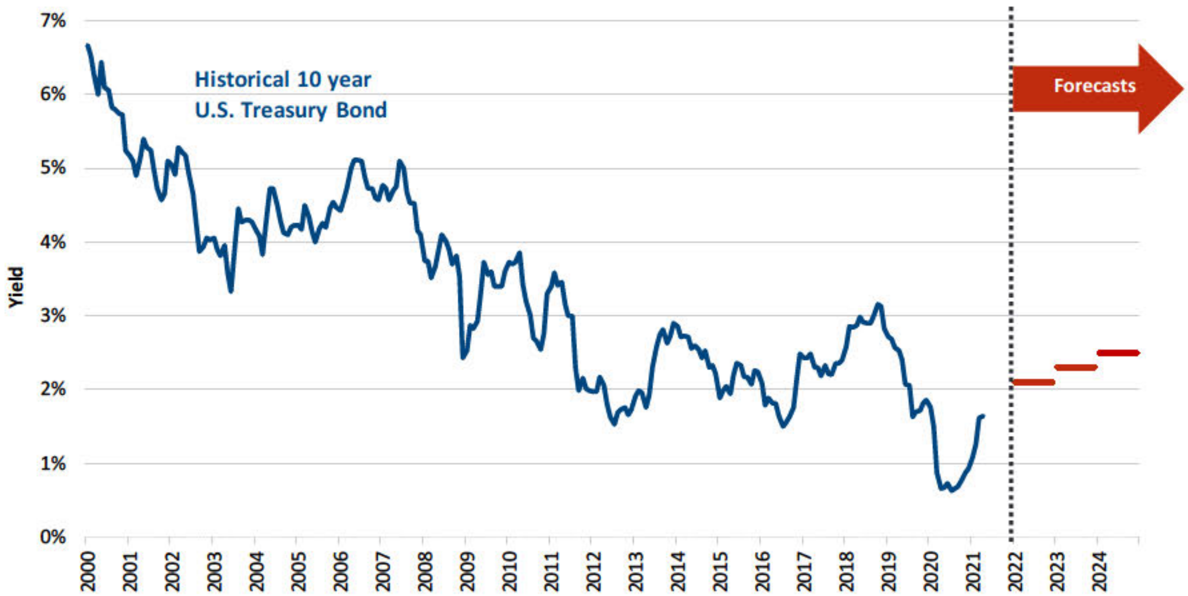
[51] Bloomberg, accessed May 10, 2021
[52] Wolters Kluwer Blue Chip Economic Indicators and PwC Analysis, May 2021 (2022) and March 2021 (2023-24), p. 14.

Figure 3
Historical and Projected Ten-Year Treasury Bond Yields[53]



Source: Historical data from Bloomberg. Forecasts from Blue Chip Economic Indicators March and May 2021 issue.

Risk Premiums[54]

Q. What is the current evidence regarding market volatility?

A. During the early months of COVID-19, financial markets became extremely volatile as shown in near-term common volatility measures, such as the VIX, which is frequently referred to as the market's fear index. The VIX reached an all-time high of 82.69 on March 16, 2020, which was higher than the peak of 80.86 during the Financial Crisis. However, the VIX has slowly retreated from recent highs to between 16.7 to 27.5 in May 2021 with the highest level seen at the beginning of the month on May 12, 2021.[55] As a result, investors are faced with

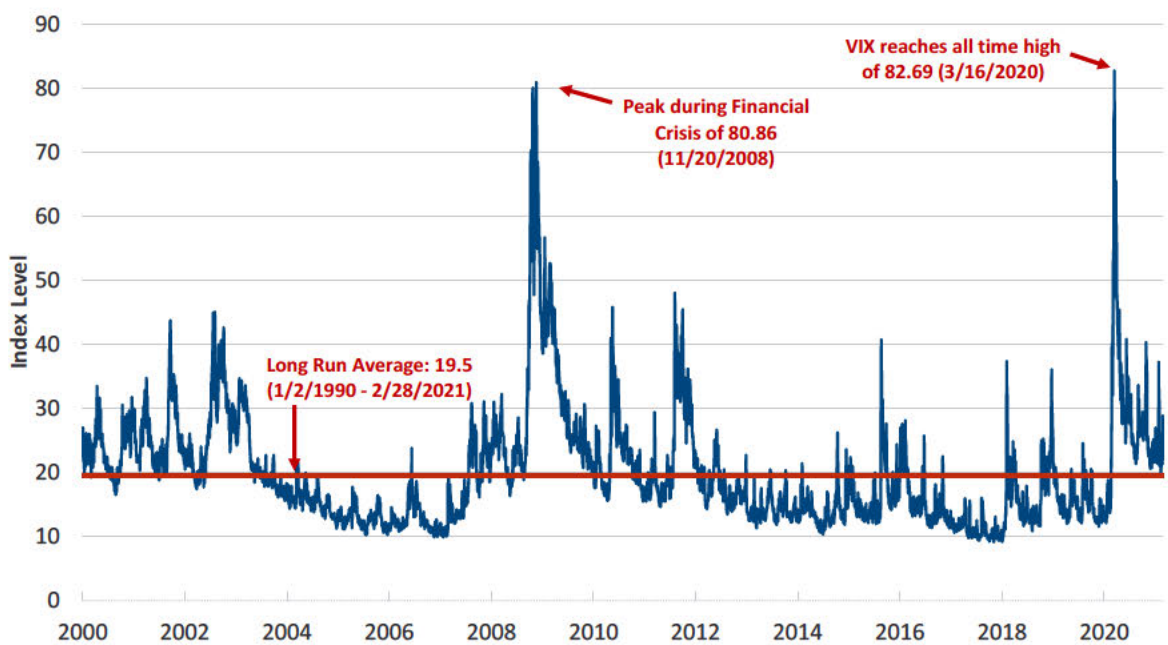
[53] Id.

[54] In past proceedings, I have considered the spread between utility bond yields and government bonds yields over the long term as well as over a recent period to assess whether the spread is elevated. Because the current spread is comparable to the long-term average, I shall not address the issue – not do I consider any potential impact on the MRP or forecasted risk-free rate.

[55] Bloomberg, as of February 28, 2021 and CBOE as of January 27, 2021. (https://www.google.com/search?q=VIX+cboe&sourceid=ie7&rls=com.microsoft:en-US:IE-Address&ie=&oe=#spf=1611799158418).

somewhat higher volatility today than before the COVID-19 pandemic. Because a higher market volatility implies a higher risk premium, the developments in market volatility are relevant to PGE's cost of equity.

Figure 4
VIX

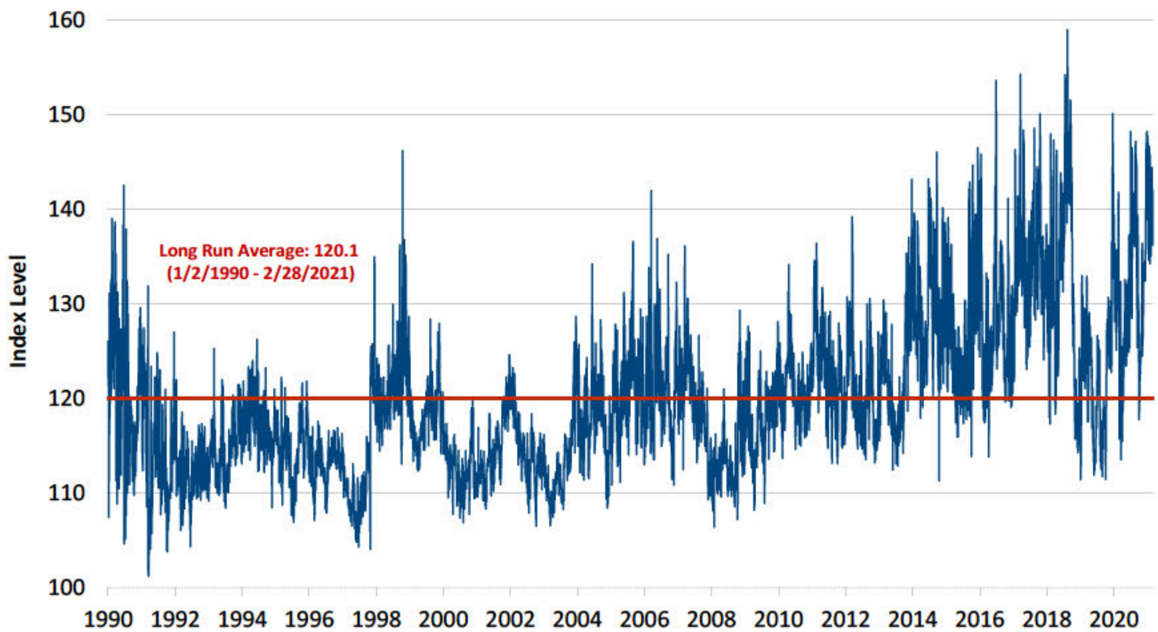


Source: Bloomberg as of 2/28/2021

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),[56] 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 5 below shows the development in the SKEW since 2005 and that the index has recently increased following a period of declining SKEW. The index spiked over 155.3 on May 28, 2021, which is well above its long run average of 120.1. The recent spike in the SKEW shows that investors continue to pay for protection against downside risks.

[56] For example, http://www.cboe.com/products/vix-index-volatility/volatility-indicators/skew.

Figure 5
SKEW



Source: Bloomberg as of 2/28/2021

While the current level of the VIX is close to its long-run average the very high level of the SKEW is consistent with investors being cautious about investing in equity. Such circumstances lead investors to require a higher premium to invest in assets or financial instruments that are not risk-free.

Q. What is the Market Risk Premium?

A. In general, a risk premium is the amount of "excess" return – above the risk-free rate of return – that investors require to compensate them for taking on risk. As illustrated in Figure 1 the riskier the investment, the larger the risk premium investors will require.

The 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,[57] the MRP is a highly relevant benchmark indicating the level of risk compensation demanded by capital market participants. It is also a direct input necessary to estimating the cost of equity using the CAPM and other risk-positioning models.

Q. Please explain the current evidence related to the MRP.

A. Bloomberg's forward looking estimate of the MRP for the U.S. increased to as high as 9.84 percent in March 2020 and remains high at an average of 8.55 percent for the last two weeks of April reaching 8.95 percent on April 30th – albeit lower compared to March 2020 levels, the market risk premium has increased recently.[58]

Figure 6
Bloomberg's Daily Market Risk Premium and Risk Free Rate
(Jan. 2020 – Apr. 2021)

[57] 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.
[58] Bloomberg, as of April 30, 2021. Measured over a 10-year U.S. Treasury bond.

Q. Are higher risk premiums relevant given that treasuries are near historic lows?

A. Yes – this is highly relevant for cost of equity estimation as current risk-free rates are extremely low. On March 9, 2020, the entire U.S. yield curve settled below 1.00% for the first time in history.[59] Since then, U.S. Government bond yields have increased with the 20-year and 30-year bond yields at 2.2%.

As shown above in Figure 9, the MRP has also increased as the risk-free rate declined. Further, as shown in both academic and industry analyses, the allowed risk premium over the risk-free rate is inversely related to the risk-free rate. For example, Villadsen et al. (2017) found that the allowed risk premium increases by approximately 0.44% for each 1% decline in the risk-free rate for the period 1990 to 2015.[60] Morin finds that the risk premium increases by 0.52% for each 1% decline in the risk-free rate.[61] As shown in Figure 9 above, this phenomenon is also documented in the forward-looking market risk premium calculated by Bloomberg. According to Bloomberg, the MRP is 8.05 – 8.45% over a 20-year treasury bond in late April,[62] which is higher than the historical average MRP of about 7.25 percent. It is also an increase over the forward-looking MRPs at the end of 2019 of 6.48%, which were much more in line with the historical average MRP.[63]

Q. Is there evidence that the MRP will remain elevated going forward?

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[59] According to the Federal Reserve, the yield on the 10-year, 20-year, and 30-year Treasury bonds on March 9, 2020 was 0.54%, 0.87%, and 0.99% respectively. These yields have since increased slightly. Source:https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

[60] Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe, "Risk and Return for Regulated Industries," Academic Press, 2017, pp. 118-119.

[61] Roger A. Morin, "New Regulatory Finance," Public Utilities Reports, Inc., 2006, pp. 123-125.

[62] Bloomberg, as of May 14, 2021, 2021. The 8.05 – 8.45% MRP is relative to the contemporaneous yield over a 20-Yr treasury bond. Relative to the contemporaneous yield over a 10-Yr treasury bond, the Bloomberg reported MRP were 8.55% and 8.95%.

[63] Id.

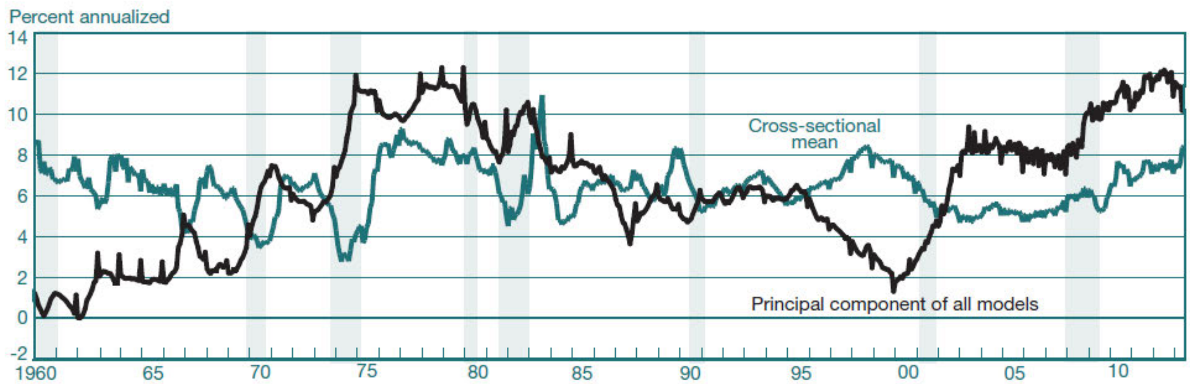
A. Yes. In 2015, Duarte and Rose of the Federal Reserve of New York performed a study that aggregated the results of many models of the required MRP in the United States and tracked them over time.[64] This analysis found a very high MRP after the financial crisis, relative to time periods prior to the crisis.

The authors estimated the MRP that resulted from a range of models each year from 1960 through the time of their study. The authors then reported the average as well as the first principal component of the results.[65] The authors found that the models used to determine the risk premium were converging to provide comparable estimates and that the average annual estimate of the MRP had reached an all-time high in 2012-2013. (Figure 7 below is a copy of the summary chart from Duarte and Rosa's 2015 paper). These directional trends identified by Duarte and Rosa are reasonably consistent with those observed from Bloomberg and they further support the proposition that the elevation of the MRP over its historical pre-crisis levels was a persistent feature of capital markets in the time following the financial crisis. Specifically, the financial crisis saw high volatility and a flight to quality – similar to conditions seen in 2020 in response to the COVID-19 pandemic and the period during which the authors found a high MRP broadly coincide with the period of low interest rates. Therefore, it is reasonable to expect that the current MRP will remain elevated compared to historical levels, especially given the uncertainty related to the extent of economic and financial impacts from COVID-19 and the historically low interest rates.

[64] Fernando Durate and Carlo Rosa, "The Equity Risk Premium: A Review of Models," *Federal Reserve Bank of New York*, December 2015 ("Duarte and Rosa, 2015") https://www.newyorkfed.org/research/staff_reports/sr714.html.

[65] Duarte and Rosa emphasize the "first principal component" of the 20 models. This means that the authors used statistics to compute the weighted average combination of the models that captures the variability among the 20 models over time.

Figure 7
Duarte and Rosa's Chart 3
One-Year Ahead MRP and Cross-Sectional Mean of Models



Q. Please summarize how the economic developments discussed above have affected the return on equity and debt that investors require.

A. Utilities rely on investors in capital markets to provide funding to support their capital expenditure programs 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 affected by the recent market development and in particular the increase in the market risk premium, so there are reasons to believe that their risk aversion remains elevated relative to pre-COVID-19 levels. As PGE is expected to be compensated as a utility on the equity component of its rate base, the same factors would affect PGE's equity.

Q. How does this impact the cost of equity estimation for PGE?

A. It is important to remember that the cost of equity and capital structure established for PGE in this proceeding is expected to be in effect beyond the current extraordinary impacts of the COVID-19 pandemic. The analysis and recommendations should reflect expected market conditions that will prevail over the relevant rate period and not exclusively the current market conditions. As discussed further below, many of the inputs to the cost of equity estimation methodologies are currently at unprecedented levels. Sole reliance on current economic and financial conditions to estimate PGE's cost of equity would unfairly lock PGE and their customers into the current economic and financial environment. Doing so would also not provide a fair return, especially when compared to other utilities that did not undergo a cost of capital proceeding during this period. However, the current conditions create an exorbitant amount of uncertainty about the future and, if the financial crisis can be used as a guide, investors' heightened perception of risk are likely to linger.

C. Estimating the Cost of Equity

Q. How do you go about estimating the cost of equity for PGE?

A. First, I select a sample of electric utilities, whose characteristics resemble those of PGE. I also look at results from a group of highly regulated gas and water utilities. Second, I estimate the cost of equity for the sample using several estimation methods to ensure that my measure reasonably reflects investor expectations. Third, I assess PGE's specific risks to determine a reasonable range given the company's specific characteristics and the current economy.

Proxy Group Selection

Q. How do you identify proxy companies of comparable business risk to PGE?

A. I select a sample of publicly traded electric utilities, whose characteristics resemble those of PGE and as a second benchmark a group of natural gas and water utilities. The proxy companies are similar to PGE in that they are rate regulated by state utility commissions, provide customers a product through a network of assets, and rely on substantial capital to provide service, i.e., they are capital intensive as is PGE. The primary electric sample further has the advantage of being in the same industry.

Q. Why are you including gas and water utilities when evaluating the cost of capital for an electric utility?

A. For several reasons. First, the electric industry share regulatory characteristics with the natural gas and the water utility industry as the industries all are regulated and commonly by the same regulatory body. They all rely on a network of assets to distribute a commodity, are capital intensive, and serve a mix of residential, commercial, and industrial customers. Second, investors make comparisons across regulated companies, so it becomes important to consider whether the returns awarded PGE are comparable not only to other electric utilities but also to other similar risk benchmarks – I consider a broader sample of natural gas and water utilities a reasonable benchmark. Third, the electric (and gas) industry is expected to undergo substantial changes as customers, regulators and the legislature focus on carbon reductions. This means that initiatives in a specific state influences stock prices and analysts' evaluations along with more fundamental operating and market conditions. I therefore select a group of other utilities, where there are less carbon considerations,[66] to assess whether the estimates from the electrics are reasonable.

I note that my recommended ROE for PGE is fully supported by the electric utility sample but I find the gas and water samples provides additional confirmation of the estimates.

Q. Please summarize how you selected the members of the Electric Sample and the Gas & Water Samples.

A. To identify companies suitable for inclusion, I started with the universe of publicly traded companies in the electric, natural gas and water utility industries as identified by Value Line Investment Analyzer (Value Line). I started with Value Line's list of publicly traded

[66] More recently, carbon considerations have become an issue for gas LDCs, too.

companies classified as electric, gas LDCs or water utilities. Next, I reviewed business descriptions and financial reports of these companies and eliminated companies that had less than 50% of their assets dedicated to regulated utility activities in their industry, e.g., electricity, natural gas or water utility services.

With 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 cut their dividends or engaged in substantial merger and acquisition (M&A) activities over the relevant estimation window.[67] I eliminated companies with such 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 financial distress. I generally 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 companies have an investment grade credit rating[68] and more than $300 million in market capitalization for liquidity purposes. A final, and fundamental, requirement is that the proxy companies have the necessary data available for estimation. I also eliminated Portland General Electric Company from the estimation process to avoid any impact of the PGE's data on the estimation results used to assess PGE's cost of capital.[69]

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[67] As described in Sections 5B and 5C, the CAPM requires five years of historical data, while the DCF relies on current market data.

[68] In some cases, a proxy company does not have a credit rating from any of the major rating agencies. However, if they were to be rated, they would receive an investment grade rating. In these instances, I assign the company the average credit rating of the rest of the proxy group.

[69] FirstEnergy was also eliminated due to the ongoing investigations into Ohio's nuclear subsidiaries.

Q. What are the characteristics of the Proxy Groups?

A. I calculate my results for both the electric proxy group and for the combined Gas and Water Utility Proxy Group. The proxy group(s) are comprised of electric utilities, and gas and water utilities, respectively. The final proxy group consists of 32 electric utilities, supported by 9 gas and 7 water utilities. The characteristics of the electric utility proxy companies are listed in Table 5 below.

The electric utility companies are distribution, transmission and commonly the production of a commodity to end customers. The natural gas and water utilities are engaged in the distribution of a commodity through a network of pipes and mains.[70] While the product differs across gas and water utilities, they are all focused on distribution, a mix of residential, commercial and industrial customers and all are regulated. Further, the electric proxy group companies have an average credit rating of approximately BBB, which is in line with PGE's credit rating of BBB+ from S&P Ratings. The natural gas and water companies have slightly higher credit ratings.

Table 5 and Table 6 report the proxy companies' annual revenues for the most recent year; most commonly 3/31/2021 and also reports the market capitalization, credit rating, beta and growth rate. The annual revenue as well as the market cap was obtained from Bloomberg. The credit rating is reported by Bloomberg.[71] The growth rate is a weighted average between estimates from Thomson Reuters and *Value Line*. Betas were obtained from *Value Line*.

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[70] Some water utilities are also engaged in water production at wells or other facilities.
[71] In cases where a company does not have a S&P rating from Bloomberg, Moody's rating was obtained from Moody's, annual reports, or Bloomberg.

Table 5
Electric Utility Proxy Group

Company	Annual Revenue (2020) ($MM)	Regulated Assets	Market Cap. (Q1 2021) ($MM)	Value Line Beta	S&P Credit Rating	Moody's Credit Rating	Long-Term Growth Estimate
	[1]	[2]	[3]	[4]	[5]		[6]
ALLETE	$1,197	MR	$3,572	0.90	BBB	WR	9.1%
Alliant Energy	$3,401	R	$13,180	0.85	A-	WR	5.7%
Amer. Elec. Power	$15,452	R	$41,719	0.75	A-	Baa2	6.2%
Ameren Corp.	$5,920	R	$20,329	0.80	BBB+	WR	7.1%
Avista Corp.	$1,345	R	$3,217	0.95	BBB	Baa2	6.9%
Black Hills	$1,793	MR	$4,159	1.00	BBB+	Baa2	4.9%
CMS Energy Corp.	$6,899	R	$17,207	0.75	BBB+	Baa2	7.2%
CenterPoint Energy	$7,798	R	$12,240	1.15	BBB+	Baa2	-3.3%
Consol. Edison	$12,689	R	$24,921	0.75	A-	Baa2	3.2%
DTE Energy	$12,933	R	$25,278	0.95	BBB+	Baa2	6.2%
Duke Energy	$24,069	R	$72,162	0.85	A-	Baa2	5.0%
Edison Int'l	$13,748	R	$22,514	0.95	BBB	Baa3	2.9%
Entergy Corp.	$10,531	MR	$19,647	0.95	BBB+	Baa2	5.6%
Evergy Inc.	$5,409	R	$13,384	0.95	A-	Baa2	5.7%
Eversource Energy	$9,357	R	$28,799	0.90	A-	Baa1	7.0%
Exelon Corp.	$34,182	R	$42,102	0.95	BBB+	Baa2	4.9%
IDACORP Inc.	$1,376	R	$5,021	0.80	BBB	Baa1	3.3%
MGE Energy	$556	R	$2,584	0.70	AA-	n/a	4.7%
NextEra Energy	$17,110	R	$144,727	0.90	A-	n/a	8.7%
NorthWestern Corp.	$1,264	R	$3,470	0.95	BBB	Baa2	4.3%
OGE Energy	$3,322	R	$6,470	1.05	BBB+	WR	4.9%
Otter Tail Corp.	$917	R	$1,899	0.85	BBB	WR	8.2%
Pinnacle West Capital	$3,622	R	$9,004	0.90	A-	WR	4.1%
Public Serv. Enterprise	$9,711	R	$29,610	0.90	BBB+	Baa1	3.1%
Sempra Energy	$11,600	R	$39,444	0.95	BBB+	Baa2	6.9%
Southern Co.	$21,267	R	$64,403	0.95	A-	Baa2	6.3%
Unitil Corp.	$427	R	$710	0.85	BBB+	n/a	4.8%
WEC Energy Group	$7,825	R	$28,568	0.80	A-	Baa1	6.3%
Xcel Energy Inc.	$12,256	R	$34,620	0.80	A-	Baa1	6.3%
Electric Sample	$8,896		$25,343	0.89	BBB+		5.4%

Sources and Notes:
[1]: Bloomberg as of April 30, 2021.
[2]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[3]: See Schedule No. BV-3 Panels A through I.
[4]: See Schedule No. BV-10
[5]: Bloomberg as of April 30, 2021.
[6]: See Schedule No. BV-5.

I note that CenterPoint Energy currently does not have a positive growth rate, so the DCF model was not implemented for this company.

Table 6
Panel A Gas Utility Proxy Group

Company	Annual Revenue (2020) ($MM)	Regulated Assets	Market Cap. (Q4 2020) ($MM)	Value Line Beta	S&P Credit Rating	Long-Term Growth Estimate
	[1]	[2]	[3]	[4]	[5]	[6]
Atmos Energy	$2,860	R	$12,274	0.80	A	6.9%
Chesapeake Utilities	$488	R	$1,869	0.80	A-	6.3%
New Jersey Resources	$1,793	MR	$3,338	0.95	A-	8.2%
NiSource Inc.	$4,682	R	$8,793	0.85	BBB+	8.8%
Northwest Natural	$774	R	$1,459	0.80	BBB+	4.3%
ONE Gas Inc.	$1,530	R	$4,150	0.80	A	6.1%
South Jersey Inds.	$1,541	R	$2,232	1.05	BBB	7.3%
Southwest Gas	$3,299	R	$3,516	0.95	BBB+	7.0%
Spire Inc.	$1,801	R	$3,323	0.85	A-	6.3%
Average	$2,085		$4,550	0.87	A-	6.8%

Sources and Notes:
[1]: Bloomberg as of March 31, 2021.
[2]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[3]: See Schedule No. BV-3 Panels A through I.
[4]: See Schedule No. BV-10
[5]: Bloomberg as of March 31, 2021.
[6]: See Schedule No. BV-5.

Table 7
Panel B Water Utility Proxy Group

Company	Annual Revenue (2020) ($MM)	Regulated Assets	Market Cap. (Q4 2020) ($MM)	Value Line Beta	S&P Credit Rating	Long-Term Growth Estimate
	[1]	[2]	[3]	[4]	[5]	[6]
Amer. States Water	$488	R	$2,874	0.65	A+	5.4%
Amer. Water Works	$3,777	R	$27,177	0.85	A	7.6%
Artesian Res Corp	$88	R	$354	0.75	A	4.0%
California Water	$794	R	$2,672	0.65	A+	8.6%
Essential Utilities	$1,463	R	$11,431	0.95	A	5.0%
Global Water Resources Inc	$39	R	$334	0.75	A	15.0%
Middlesex Water	$142	R	$1,264	0.70	A	3.7%
SJW Group	$565	R	$1,953	0.85	A-	7.4%
York Water Co. (The)	$54	R	$619	0.80	A-	5.0%
Average	$823		$5,409	0.77	A	6.9%

Sources and Notes:
[1]: Bloomberg as of March 31, 2021.
[2]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[3]: See Schedule No. BV-3 Panels A through I.
[4]: See Schedule No. BV-10
[5]: Bloomberg as of March 31, 2021.
[6]: See Schedule No. BV-5.

Q. How do the proxy companies compare to PGE in terms of financial metrics?

A. PGE's revenue was $2,145 for 2020.[72] Compared to the annual revenue of the proxy companies, PGE's revenue is smaller than the electric companies, larger than the water companies but very much in line with that of the gas companies. PGE's senior unsecured credit rating is BBB+ from S&P Global Ratings[73] and in line with the average credit rating of the electric utility proxy group but below that of the natural gas and water utilities. Lastly, PGE is an integrated electric utility as is most of the companies in the electric utility proxy group. Also similar to the average proxy company, PGE has more than 80% of its assets subject to regulation.[74]

Q. What regulatory capital structure did you use for PGE?

A. As recommended by PGE Company Witnesses Jardon Jaramillo and Jaki Ferchland, I use a capital structure including 50% equity in my recommendation. The Commission has in the past accepted a capital structure including 50 percent equity for PGE.

<u>DCF Based Estimates</u>

Q. Please describe the DCF model's approach to estimating the cost of equity.

A. The DCF model attempts to estimate the cost of capital for a given company directly, rather than based on its risk relative to the market as the CAPM does. The DCF method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow – literally a stream of expected "cash

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[72] Value Line Investment Survey as of April 23 2021.
[73] S&P, "Portland General Electric," March 27, 2020.
[74] EEI 2019 Financial Review (2019 is the most recent year available); FinancialReview_2019.pdf (eei.org)

flows" discounted at a risk-appropriate discount rate. When the cash flows are dividends, that discount rate is the cost of equity capital:

$$\boldsymbol{P_0} = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \qquad (3)$$

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. In this sense, 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 its future 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:

$$\boldsymbol{r} = \frac{D_1}{P_0} + \boldsymbol{g} = \frac{D_0}{P_0} \times (\mathbf{1} + \boldsymbol{g}) + \boldsymbol{g} \qquad (4)$$

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 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 (iii) versions that combine aspects of (i) and (ii).[75] One such alternative expands the Gordon Growth model to three stages. In the multistage model, earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period.[76]

In my implementation of the multi-stage DCF, I assume that companies grow their dividend for five years at the forecasted company-specific rate of earnings growth, with that growth then tapering over the next five years toward the growth rate of the overall economy (i.e., the long-term gross domestic product (GDP) growth rate forecasted to be in effect ten years or more into the future).

DCF Inputs and Results

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 proxy group. For the single-stage DCF and for 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 *IBES*.

[75] 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.
[76] See Exhibit 905 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.

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 percent from BCEI.[77] Thus, the long-run (or terminal) growth rate in the multi-stage model is nominal GDP growth.

Additionally, I relied on the dividend yield of the companies, which I estimate using the most recently available dividend information (currently) and the average of the last 15 days of stock prices ending April 30, 2021. As the single largest advantage of the DCF model is that it uses current market information, I find it is important to use a relatively short time period to determine the dividend yield – yet to avoid the bias caused by any one day. I believe a 15-day average accomplishes that goal. Because the stock price of utilities currently is higher than they historically have been and because some companies engage in share buybacks, the dividend yield underestimates the yield on cash distributions to investors.

Q. Please address the input data in the DCF model.

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 sufficiently long horizon, but estimates are typically only available for 3-5 years.

One issue with the data is that it includes solely 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.

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[77] See Blue Chip Economic Indicators, March 2021, p. 14.

A second issue is that the flight to quality has resulted in higher than usual stock prices for water utilities and hence lower than usual dividend yields. As a result, the dividend yield may be downward biased. The multi-stage DCF model additionally requires a measure of the long-term GDP growth.

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 Table 8.[78]

Table 8
DCF Model Results at 50% Equity

	Single-Stage	Multi-Stage
Electric Sample	10.1%	8.4%
Gas Sample	11.0%	8.5%
Water Sample	10.9%	7.1%

Q. How do you interpret the results of your DCF Analyses?

A. The DCF model calculates the electric proxy group's ROE at 8.4 to 10.1 percent and provides a wider range for the gas LDC and water utility samples at 7.1 to 11 percent. Because the DCF model requires forecasted growth rates that are based on stable economic conditions to satisfy the constant dividend growth assumption, the model's results are currently subject to uncertainty and it is necessary to rely on additional methods. I believe the results from the multi-stage model currently understates the cost of equity for a regulated entity, so that a reasonable range based on the results above is in the range of 9¼ to 10 percent when using the DCF results alone.[79]

[78] Details of the DCF model are included in Exhibit 903, Schedules BV-5 to BV-8 for the electric sample and in Exhibit 904, Schedules BV-5 to BV-8 for the gas and water sample.
[79] The lower bound was determined as the average of the single-stage and the multi-stage result for the electric sample.

Risk Premium Model Estimates

Q. Did you estimate the cost of equity that results from 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 this relationship to the relevant (prevailing or forecast) risk-free interest rate:

$$Cost\ of\ Equity = r_f + Risk\ Premium \tag{5}$$

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 properly consider the interest rate regime at the time the ROE was awarded. This implementation ensures that I can compare allowed ROE granted at different times and under different interest rate regimes.[80]

Q. How did you use rate case data to estimate the risk premiums for your analysis?

A. The rate case data from 1990 through March 2021 (most recent quarter) is derived from

[80] The premium is estimated by comparing the average excess yield on 20-year versus 10-year Government Bonds over the period 1990-2020, using data from Bloomberg.

Regulatory Research Associates.[81] Using this data I compared (statistically) the average allowed rate of return on equity granted by U.S. state regulatory agencies in electric utility rate cases to the average 20-year Treasury bond yield that prevailed in each quarter.[82] 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:

$$Risk\ Premium = A_0 + A_1 \times (Treausury\ Bond\ Yield) \qquad (6)$$

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 my results for the respective classifications of rate cases below in Table 9.[83] I note that the results displayed in Table 9 below shows that the risk premium model fits the data well as the R-squared is above 80% for the more recent period of 2011 to today and above 2/3 for the full period. The R-squared is a measure of how well the data fits the model and these R-squared indicate solid results.

[81] S&P Market Intelligence, as of April 2021.
[82] I rely on the 20-year government bond to be consistent with the analysis using the CAPM to avoid confusion about the risk-free rate. While it is important to use a long-term risk-free rate to match the long-lived nature of the assets, the exact maturity is a matter of choice.
[83] Exhibit 903, Schedule BV-16 contains my risk premium analysis.

Table 9
Implied Risk Premium Model Estimates

	R Squared	Estimate of Intercept (A0)	Estimate of Slope (A1)	Implied Cost of Equity Range
	[1]	[2]	[3]	[4]
Electric Utility	0.859	8.53%	-0.552	9.8%

Sources and Notes:
[1]-[3]: Estimated Using S&P Market Intelligence, as of March 2021
[4]: Risk-free rate of 2.8%

The negative slope coefficient reflects the empirical fact that regulators grant smaller risk premiums when risk-free interest rates (as measured by Treasury bond yields) are higher. This is consistent with past observations that the premium investors require to hold equity over government bonds increases as government bond yields decline. In the regression described above the risk premium declined by less than the increase in Treasury bond yields. Therefore, the allowed ROE on average declined by less than 100 bps when the government bond yield declined by 100 bps.

Q. What conclusions did you draw from your risk premium analysis?

A. The result in Table 9 indicates a ROE of 9.8% for an average electric utility based on the risk premium model, which is above the electric utility based estimates from the DCF models but below the highest estimates from the gas and water utilities. While the risk premium model is based on historical 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 estimating utility ROEs. Because the risk premium analysis as implemented takes into account the interest rate prevailing during the quarter the decision that granted an ROE used in the analysis 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.

The CAPM Based Cost of Equity Estimates

Q. Please briefly explain the CAPM.

A. CAPM assumes the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets such that the returns investors expect to receive on their investments are commensurate with the risk of those assets relative to the market as a whole. The CAPM posits a risk-return relationship known as the Security Market Line (see Figure 2 in Section 3), 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:

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \quad (7)$$

$\boldsymbol{r_S}$ 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 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 so as 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 (7), estimating the cost of equity for a given company requires a measure of the risk-free rate and the MRP, as well as a measure of the stock's beta. There are several choices and sources of data that inform the selection of these inputs. I discuss these issues below (Additional technical detail, along with a discussion of the finance theory underlying the CAPM is provided in Exhibit 905.

Q. What value did you use for the risk-free rate?

A. I use the yield on a 20-year U.S. Treasury bond as the risk-free rate for purposes of my analysis. Recognizing the fact that the cost of capital set in this proceeding will be in effect from 2022 and onwards, I rely on a forecast of what Government bond yields will be mid-way through the 2022-2024 period. Relying on the May 2021 BCEI for 2022 and the March 2021 BCEI for 2023 and 2024, the estimated yield on 10-year U.S. Treasury bond yields will be 2.1% in 2022, 2.3% in 2023, and 2.5% in 2024, so I rely on the 2023 (midpoint) value of 2.3%.[84] I then adjust this value upwards by 50 basis points to reflect the historical maturity

[84] Wolters Kluwer Blue Chip Economic Indicators and PwC Analysis, Consensus Forecasts, March 2021, p. 3 and p. 14 and BCEI May 2021 p. 3.

premium for the 20-year U.S. Treasury bond yield over the 10 U.S. Treasury bond yield.[85] This gives me a risk-free rate of 2.80%.

Additionally, it is important to recognize the implication of higher spreads between utility bond yields and U.S. Government bond yields. In the past, I have also considered the spread between utility bond yields and government bond yields, but as of now the spread is elevated by about 15 bps, so I make no adjustments for this spread.

Q. What value did you use for the MRP?

A. Like the cost of capital itself, the MRP is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can expect to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable. Rather, it 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' income returns over a long historical period.[86] The average market risk premium from 1926 to the present (2020) is 7.25%.[87]

However, investors may require a higher or lower risk premium, reflecting their investment alternatives and aggregate level of risk aversion at any given time. As explained in Section 4, there is evidence that investors' level of risk aversion is elevated relative to the time before the COVID-19 pandemic and may remain elevated for some time, even after the pandemic. In recognition of the evidence that forward-looking measures of expected market

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[85] This maturity premium is estimated by comparing the average excess yield on 20-year versus 10-year Government Bonds over the period 1990-2020, using data from Bloomberg.
[86] The longest period for which Duff & Phelps reports data is 1926 to current. Based on financial textbooks such as Ross, Westerfield and Jaffe, "Corporate Finance," 10'th Edition, 2013, pp. 324-327, I use the longest period for which reliable estimates are available – in this case 1926 to 2020.
[87] Duff & Phelps, Ibbotson SBBI 2021 Valuation Yearbook 10-21.

equity risk premium are higher than the long-term historical average, I also perform a CAPM calculation using Bloomberg's forecasted MRP of about 8% for the last two weeks of April, 2021. I note that this is conservative as the April 30, 2021 forecasted MRP is 8.45%.[88]

Q. Please summarize the parameters of the scenarios and variations you considered in your CAPM and ECAPM analyses.

A. Both Scenario 1 and Scenario II use the forecasted 20 year U.S. Treasury rate for 2022-24 of 2.80%. Scenario I combine that with a historical MRP of 7.25%, while Scenario II combines the risk-free rate with a forecasted MRP of 8%.

Q. What betas did you use for the companies in your proxy groups?

A. I used *Value Line* betas, which are estimated using the most recent five years of weekly historical returns data.[89] The *Value Line* levered equity betas are reported in Figure 11 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 on the proxy companies used to estimate the ROE, the financial risk associated with an equity investment in PGE's rate base is correspondingly greater than the financial risk borne by investors in the proxy companies' publicly traded stock.[90] Importantly, 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. Consequently, standard textbook techniques are applied to unlever the *Value Line* betas reported in Figure 11 above and relever the

[88] Bloomberg as of April 30, 2021.
[89] See Value Line Glossary, accessible at http://www.valueline.com/Glossary/Glossary.aspx
[90] As shown in Figure 4, the higher (lower) the debt ratio is the higher (lower) the cost of equity, all else equal.

resulting asset betas at PGE's regulatory capital structure. See Exhibit 903, Schedules BV-13 to BV-15.[91]

The Empirical CAPM

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.[92] 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 second variation on the CAPM that I employ makes use of these empirical findings. It estimates the cost of capital with the equation,

$$\boldsymbol{r_S = r_f + \alpha + \beta_S} \times (\boldsymbol{MRP - \alpha}) \quad (2)$$

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 (2) 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 in Figure 2, which results in a Security Market Line that more closely matches the results of empirical tests. This adjustment is portrayed in Figure 14 below. In other words,

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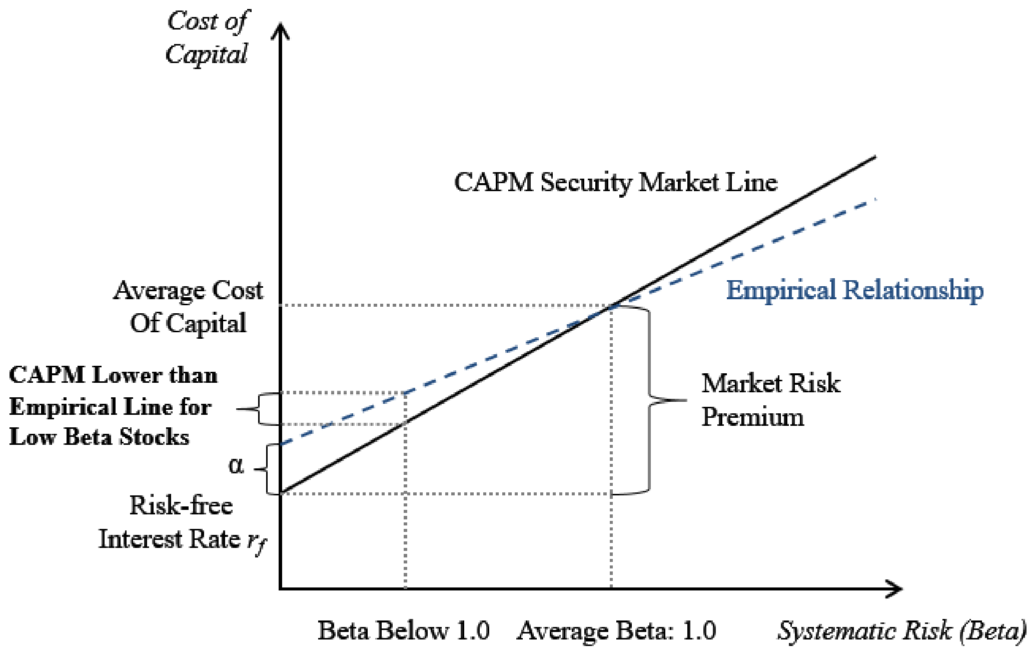
[91] Exhibit 905 provides a detailed description of the standard textbook formulas used to implement the "Hamada" technique for unlevering measured equity betas based on the proxy companies' capital structures to calculate "asset betas" that measure the proxy companies' business risk independent of the financial risk impact of differing capital structures. The proxy group average asset betas are then relevered at the target capital structure (i.e., PGE's regulatory capital structure), with the precise relevered beta depending on the specific version of the unlevering/relevering formula employed.

[92] *See* Figure A-2 in Exhibit 905 for references to relevant academic articles.

the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

Figure 8
The Empirical Security Market Line



Q. Why do you use the ECAPM?

A. Academic research finds that the CAPM has not generally performed 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%[93] and 7.32%.[94] I apply an alpha parameter of 1.5% in my application of the ECAPM. Exhibit 905 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 electric sample are presented in Table 10 below. The results for the natural gas and water samples are presented in Tables 11 and 12, respectively.[95] The ranges of results for each model (CAPM and ECAPM) reflect the application of different specific versions of the textbook formulas used to account for the impact of different financial leverage on financial risk.

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[93] Black, Fischer. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18.
[94] Fama, Eugene F. and Kenneth R. French. 1992. The Cross-Section of Expected Stock Returns. *Journal of Finance* 47 (June): 427-465.
[95] Details for the CAPM / ECAPM model for the electric sample are in Exhibit 903, Schedule No. BV-9 to BV-15. The details for the gas and water sample are in Exhibit 904, Schedule No. BV-9 to BV-15.

Table 10
CAPM and ECAPM Summary at 50% Equity

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Electric Sample		
Financial Risk Adjusted Method		
CAPM	10.1%	10.8%
ECAPM (α = 1.5%)	10.3%	11.0%
Hamada Adjustment Without Taxes		
CAPM	9.9%	10.7%
ECAPM (α = 1.5%)	9.9%	10.7%
Hamada Adjustment With Taxes		
CAPM	9.8%	10.5%
ECAPM (α = 1.5%)	9.9%	10.6%

Sources and Notes:
[1]: Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%.
[2]: Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%.

Table 11
Panel A – CAPM and ECAPM Summary for Natural Gas Sample

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Gas Sample		
Financial Risk Adjusted Method		
CAPM	10.3%	11.2%
ECAPM (α = 1.5%)	10.6%	11.4%
Hamada Adjustment Without Taxes		
CAPM	10.2%	10.9%
ECAPM (α = 1.5%)	10.1%	10.9%
Hamada Adjustment With Taxes		
CAPM	9.9%	10.7%
ECAPM (α = 1.5%)	9.9%	10.7%

Sources and Notes:
[1]: Long-Term Risk Free Rate of 2.60%, Long-Term Market Risk Premium of 7.25%.
[2]: Long-Term Risk Free Rate of 2.60%, Long-Term Market Risk Premium of 8.00%.

Table 12
Panel B – CAPM and ECAPM Summary for Water Utility Sample

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Water Sample		
Financial Risk Adjusted Method		
CAPM	10.5%	11.3%
ECAPM (α = 1.5%)	11.0%	11.8%
Hamada Adjustment Without Taxes		
CAPM	10.2%	11.0%
ECAPM (α = 1.5%)	10.1%	10.9%
Hamada Adjustment With Taxes		
CAPM	9.8%	10.5%
ECAPM (α = 1.5%)	9.8%	10.5%

Sources and Notes:
[1]: Long-Term Risk Free Rate of 2.60%, Long-Term Market Risk Premium of 7.25%.
[2]: Long-Term Risk Free Rate of 2.60%, Long-Term Market Risk Premium of 8.00%.

Q. How do you interpret the results of your CAPM and ECAPM analyses?

A. The results in Tables 10-12 above range from 9.8% to about 10¾ percent for the electric sample ignoring the financial risk adjusted method. The results from the natural gas and water sample are consistent with this range but slightly higher.

Q. Do the results from the gas and water utilities support the ROE results above?

A. Yes. The gas utilities and water utilities exhibit similar to higher CAPM and ECAPM results.

<u>Summary of Results</u>

Q. Please summarize your results before considering where to place PGE.

A. Assuming a 50% equity capital structure for PGE, I find the reasonable range of ROE for electric utilities to be those displayed below (all figures are rounded to the nearest ¼ percent). Next, I consider PGE specific risks to inform my recommendation of a reasonable ROE for PGE.

Table 13
Summary Results for Electric Utilities at 50% Equity

CAPM/ ECAPM	9.75% - 10.75%
DCF	9.25% – 10.0%
Risk Premium	9.8%

Q. What is a reasonable range for the proxy group?

A. Based on the results above, I find that a reasonable range for the CAPM / ECAPM is 9.75 to 10.75 percent, a reasonable range for the DCF is 9.25 to 10.0 percent, and the risk premium is about 9.8 percent.

D. PGE Specific Circumstances and ROE Recommendation

Q. How does the business risk of PGE compare to that of the sample?

A. Like the companies in the electric sample, PGE's business is concentrated in the regulated electric utility industry. It also has a credit rating that is comparable to that of the sample. However, there are several areas in which PGE faces higher risk than the peer group of electric utilities. First, unlike many of its peers, PGE currently has an asymmetric deadband in its PCAM. According to Regulatory Research Associates (RRA), which is part of Standard & Poor's, the majority of electric utilities do not share power cost over or under recovery with customers.[96] Second, PGE has an asymmetric ROE test, which makes it challenging to earn the allowed ROE as only earnings in excess but not under earnings are shared with customers. Third, there is a cap on its energy efficiency decoupling mechanism, which similar to the asymmetric earnings test makes it more challenging to earn the allowed ROE. Fourth, 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.

[96] S&P Global Intelligence, "RRA Regulatory Focus: Adjustment Clauses," November 12, 2019.

Specifically, Duff & Phelps calculates a size premium that they add to the cost of equity for companies that are smaller in size. Specifically, the average electric utility in the sample has a market cap of approximately $7.9 billion, while that of PGE is about $3.7 billion, measured at year-end 2020. 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 one percent.[97]

Q. What do you recommend for PGE cost of equity in this proceeding?

A. The reasonable range as shown in Figure 18 above, is 9.25 to 10.75 percent using the DCF, CAPM/ECAPM and risk premium models, but it is more accurate to narrow that range to 9.5 percent to 10.25 percent for the electric utility industry as that is the average of the low and high estimates, respectively. I also note that the majority of my estimates are in this range and only the highest and lowest estimates fall outside the range. I understand that PGE is applying for an ROE of 9.5 percent, which I consider conservative given the range of 9.5 to 10.25 percent. Consequently, I fully support the applied for ROE.

[97] Duff & Phelps Cost of Capital Nagivator as of December 31, 2020 (assessed 1/31/2021).

VI. 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 2022. 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. 18-464 in Docket UE 335. 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 374, the Commission adopted an equity percentage of 50% for PacifiCorp in line with Staff's recommendation. The Commission stated: "We find that a more balanced capital structure serves to reduce the cost of equity to customers, without jeopardizing the financial integrity of the company. We find that a capital structure of 50 percent equity achieves that balance."[98]

Q. Does PGE expect to issue common equity between now and the end of 2022?

A. No. At this time PGE does not anticipate additional equity issuances, but we will provide an update if financing plans change.

Q. Are you seeking a different regulatory capital structure than in docket UE 335?

A. No. In UE 335, the OPUC adopted a settlement among the parties that reaffirmed PGE's regulated capital structure at 50% equity and 50% debt, and PGE was encouraged to make

[98] Order No. 20-473, Docket No. UE 374. December 18, 2020.

efforts to secure longer-term debt, rather than shorter term-debt, which it has done. PGE's long-term goal continues to be to maintain its capital structure at 50% equity and 50% debt; however, the equity ratio fluctuates around the 50% target level, due to the timing and size 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. How did PGE's accounting capital structure change following the debt issuances after the energy trading loss?

A. When examining the accounting equity ratio, PGE's capital structure consisted of increased debt following the energy trading losses given the issuances following the energy trading loss in Q4 of 2020.[99] In accordance with the other adjustments made in the case for the energy trading losses, we have removed the debt associated with the trading losses from our cost

[99] Based on PGE's results of operations and the OPUC ratio for calculating debt to equity.

of debt and we have adjusted equity to reflect a capital structure excluding the trading losses. PGE continues to target 50% debt and 50% equity over the long run.

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 the timing of it; and volatility in electricity usage because of sudden, unexpected weather changes and severe storms and wildfires. This weather risk is not mitigated by PGE's decoupling mechanism. 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 affect 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 SEC annual 10-K and quarterly 10-Q filings.[100] PGE could be vulnerable to cyber security and physical assets attacks. The electric industry is going through

[100] 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.

accelerated technological changes, which can make a basic premise of the current business model (economies of scales 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.

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. The completion of the IOC is an example of our efforts. Other examples include improving the ability to recover from catastrophic events remains a key strategic focus of PGE. 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.

VII. Qualifications

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

A. I received a Bachelor of Arts degree in economics from Northwest Nazarene University and a Master of Business Administration at the University of California, Los Angeles. I am also a certified public accountant. Prior to joining PGE, I worked at Deloitte & Touche, where I served various public utilities as an external auditor and worked in mergers and acquisitions consulting. I joined PGE in 2011, becoming the Director of Compensation and Benefits in 2013. I held this position until January 2017. I was the Controller and Assistant Treasurer for PGE through May 2020. I am currently the Senior Director of Treasury, Investor Relations, and Risk Management.

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 the 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. Dr. Villadsen, please state your educational background and experience.

A. I hold a Ph.D. from Yale University's School of Management with a concentration in accounting. I have a joint degree in mathematics and economics (Bachelor of Science and Master of Science) from University of Aarhus in Denmark. Prior to joining The Brattle Group, I was a Professor of Accounting at the University of Iowa, University of Michigan, and at Washington University in St. Louis where I taught financial and cost accounting. I have also taught graduate classes in econometrics and quantitative methods. I have worked as a consultant for Risoe National Laboratories in Denmark.

My work concentrates in the areas of regulatory finance and accounting. My recent work has focused on accounting issues, damages, cost of capital and regulatory finance. In the regulatory finance area, I have 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 decoupling on cost of capital and earnings. I have been involved in accounting 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. I have estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and railroad industry. I have filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions. My testimonies and expert reports pertain to accounting issues, damages, discount rates and cost of capital for regulated entities. A detailed vita of my qualifications is included in Exhibit 906.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
901C	Cost of Long-Term Debt
902	Standard & Poor's and Moody's Investors Service Credit Ratings
903	Cost of Equity Estimates – Electric Sample
904	Cost of Equity Estimates – Natural Gas and Water Sample
905	Technical Appendix
906	Villadsen Resume

Exhibit 901 contains confidential information and is subject to General Protective Order 21-206.

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	1/14/2021	A1	3/29/2021
Senior Unsecured	BBB+	1/14/2021	A3	3/29/2021
Short-term/ Commercial Paper	A-2	1/14/2021	P-2	3/29/2021

"Credit Opinion: Portland General Electric Company" January 14, 2021. Standard & Poor's
"Credit Opinion: Portland General Electric Company" March 29, 2021. Moody's Investors Service

Schedule No. BV-1

Table of Contents

Schedule No. BV-2

Electric Sample

Classification of Companies by Assets

Company	Company Category
ALLETE	MR
Alliant Energy	R
Amer. Elec. Power	R
Ameren Corp.	R
Avista Corp.	R
Black Hills	MR
CMS Energy Corp.	R
CenterPoint Energy	R
Consol. Edison	R
DTE Energy	R
Duke Energy	R
Edison Int'l	R
Entergy Corp.	MR
Evergy Inc.	R
Eversource Energy	R
Exelon Corp.	R
IDACORP Inc.	R
MGE Energy	R
NextEra Energy	R
NorthWestern Corp.	R
OGE Energy	R
Otter Tail Corp.	R
Pinnacle West Capital	R
Public Serv. Enterprise	R
Sempra Energy	R
Southern Co.	R
Unitil Corp.	R
WEC Energy Group	R
Xcel Energy Inc.	R

Sources and Notes:
Calculations based on EEI definitions and Company 10K filings:
R = Regulated (greater than 80 percent of total assets are regulated).
MR = Mostly Regulated (Less than 80 percent of total assets are regulated).

Schedule No. BV-3

Market Value of the Electric Sample

Panel A: ALLETE

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$2,321	$2,321	$2,271	$2,199	$2,097	$2,002	$1,850	[a]
Shares Outstanding (in millions) - Common	52	52	52	52	51	51	49	[b]
Price per Share - Common	$70	$68	$61	$83	$70	$67	$57	[c]
Market Value of Common Equity	$3,663	$3,572	$3,155	$4,268	$3,614	$3,419	$2,796	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,663	$3,572	$3,155	$4,268	$3,614	$3,419	$2,796	[f]= [d] + [e]
Market to Book Value of Common Equity	1.58	1.54	1.39	1.94	1.72	1.71	1.51	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$378	$378	$275	$556	$404	$361	$379	[j]
Current Liabilities	$575	$575	$623	$322	$400	$365	$224	[k]
Current Portion of Long-Term Debt	$304	$304	$330	$23	$106	$163	$15	[l]
Net Working Capital	$108	$108	($18)	$257	$110	$159	$170	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	#N/A N/A	#N/A N/A	#N/A N/A	#N/A N/A	$0	$1	$1	[n]
Adjusted Short-Term Debt	$0	$0	#VALUE!	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,667	$1,667	$1,420	$1,551	$1,397	$1,370	$1,551	[p]
Book Value of Long-Term Debt	$1,971	$1,971	N/A	$1,573	$1,503	$1,533	$1,566	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,971	$1,971	$1,792	$1,535	$1,628	$1,654	$1,676	
Carrying Amount	$1,806	$1,806	$1,623	$1,495	$1,513	$1,569	$1,605	
Adjustment to Book Value of Long-Term	$165	$165	$169	$39	$114	$85	$71	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,136	$2,136	N/A	$1,613	$1,617	$1,618	$1,637	[s] = [q] + [r].
Market Value of Debt	$2,136	$2,136	N/A	$1,613	$1,617	$1,618	$1,637	[t] = [s].
MARKET VALUE OF FIRM	$5,798	$5,707	N/A	$5,881	$5,231	$5,036	$4,433	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	63.17%	62.58%	N/A	72.58%	69.09%	67.88%	63.07%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	N/A	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	36.83%	37.42%	N/A	27.42%	30.91%	32.12%	36.93%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel B: Alliant Energy

($MM)

	DCF Capital	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equit	$5,766	$5,766	$5,502	$4,682	$4,232	$3,897	$3,765	[a]
Shares Outstanding (in millions) - Commo	250	250	250	237	231	228	114	[b]
Price per Share - Common	$56	$53	$47	$47	$40	$40	$36	[c]
Market Value of Common Equity	$13,975	$13,180	$11,774	$11,192	$9,211	$9,018	$4,109	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$13,975	$13,180	$11,774	$11,192	$9,211	$9,018	$4,109	[f]= [d] + [e]
Market to Book Value of Common Equity	2.42	2.29	2.14	2.39	2.18	2.31	1.09	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$200	$200	$200	$200	$200	$200	$200	[h]
Market Value of Preferred Equity	$200	$200	$200	$200	$200	$200	$200	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$755	$755	$912	$815	$726	$750	$769	[j]
Current Liabilities	$1,408	$1,408	$1,650	$1,588	$2,074	$1,165	$1,349	[k]
Current Portion of Long-Term Debt	$308	$308	$357	$260	$856	$5	$313	[l]
Net Working Capital	($345)	($345)	($381)	($513)	($492)	($411)	($267)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$336	$336	$271	$515	$431	$303	$213	[n]
Adjusted Short-Term Debt	$336	$336	$271	$513	$431	$303	$213	[o] = See Sources and Notes.
Long-Term Debt	$6,471	$6,471	$5,834	$5,377	$4,057	$4,316	$3,523	[p]
Book Value of Long-Term Debt	$7,115	$7,115	$6,462	$6,150	$5,344	$4,624	$4,050	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$8,109	$8,109	$6,920	$5,861	$5,448	$4,799	$4,336	
Carrying Amount	$6,777	$6,777	$6,190	$5,503	$4,866	$4,320	$3,836	
Adjustment to Book Value of Long-Ter	$1,332	$1,332	$730	$358	$581	$479	$501	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$8,447	$8,447	$7,191	$6,508	$5,925	$5,102	$4,550	[s] = [q] + [r].
Market Value of Debt	$8,447	$8,447	$7,191	$6,508	$5,925	$5,102	$4,550	[t] = [s].
MARKET VALUE OF FIRM	$22,622	$21,827	$19,165	$17,900	$15,336	$14,320	$8,859	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	61.78%	60.38%	61.43%	62.53%	60.06%	62.97%	46.38%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.88%	0.92%	1.04%	1.12%	1.30%	1.40%	2.26%	[w] = [i] / [u].
Debt - Market Value Ratio	37.34%	38.70%	37.52%	36.36%	38.64%	35.63%	51.36%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel C: Amer. Elec. Power

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$21,028	$21,028	$19,782	$19,243	$18,500	$17,689	$18,127	[a]
Shares Outstanding (in millions) - Common	499	499	495	493	493	492	491	[b]
Price per Share - Common	$88	$84	$81	$84	$67	$67	$65	[c]
Market Value of Common Equity	$43,876	$41,719	$40,157	$41,379	$33,080	$32,904	$31,947	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$43,876	$41,719	$40,157	$41,379	$33,080	$32,904	$31,947	[f]= [d] + [e]
Market to Book Value of Common Equity	2.09	1.98	2.03	2.15	1.79	1.86	1.76	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,258	$4,258	$5,292	$3,915	$4,135	$3,616	$4,146	[j]
Current Liabilities	$10,220	$10,220	$11,655	$7,991	$9,471	$7,915	$7,222	[k]
Current Portion of Long-Term Debt	$2,371	$2,371	$2,344	$1,818	$2,616	$2,514	$2,033	[l]
Net Working Capital	($3,591)	($3,591)	($4,019)	($2,258)	($2,720)	($1,784)	($1,042)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$3,048	$3,048	$4,464	$1,858	$2,659	$1,536	$1,221	[n]
Adjusted Short-Term Debt	$3,048	$3,048	$4,019	$1,858	$2,659	$1,536	$1,042	[o] = See Sources and Notes.
Long-Term Debt	$30,840	$30,840	$26,519	$23,996	$18,845	$16,722	$17,749	[p]
Book Value of Long-Term Debt	$36,259	$36,259	$32,882	$27,672	$24,120	$20,772	$20,825	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$37,457	$37,457	$30,172	$24,094	$23,650	$22,212	$21,201	
Carrying Amount	$31,073	$31,073	$26,726	$23,347	$21,173	$20,391	$19,573	
Adjustment to Book Value of Long-Term	$6,385	$6,385	$3,447	$747	$2,476	$1,821	$1,629	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$42,644	$42,644	$36,329	$28,419	$26,596	$22,593	$22,454	[s] = [q] + [r].
Market Value of Debt	$42,644	$42,644	$36,329	$28,419	$26,596	$22,593	$22,454	[t] = [s].
MARKET VALUE OF FIRM	$86,519	$84,362	$76,485	$69,798	$59,676	$55,497	$54,401	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	50.71%	49.45%	52.50%	59.28%	55.43%	59.29%	58.73%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	49.29%	50.55%	47.50%	40.72%	44.57%	40.71%	41.27%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel D: Ameren Corp.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$9,148	$9,148	$8,085	$7,705	$7,230	$7,064	$6,869	[a]
Shares Outstanding (in millions) - Common	256	256	247	246	244	243	243	[b]
Price per Share - Common	$84	$80	$72	$73	$55	$55	$49	[c]
Market Value of Common Equity	$21,429	$20,329	$17,715	$17,973	$13,395	$13,369	$11,868	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$21,429	$20,329	$17,715	$17,973	$13,395	$13,369	$11,868	[f]= [d] + [e]
Market to Book Value of Common Equity	2.34	2.22	2.19	2.33	1.85	1.89	1.73	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,823	$1,823	$1,464	$1,422	$1,567	$1,450	$1,458	[j]
Current Liabilities	$2,307	$2,307	$2,367	$2,392	$3,345	$2,762	$1,839	[k]
Current Portion of Long-Term Debt	$8	$8	$357	$343	$1,170	$681	$135	[l]
Net Working Capital	($476)	($476)	($546)	($627)	($608)	($631)	($246)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$889	$889	$615	$799	$960	$914	$581	[n]
Adjusted Short-Term Debt	$476	$476	$546	$627	$608	$631	$246	[o] = See Sources and Notes.
Long-Term Debt	$11,527	$11,527	$9,378	$8,250	$6,766	$6,597	$6,881	[p]
Book Value of Long-Term Debt	$12,011	$12,011	$10,281	$9,220	$8,544	$7,909	$7,262	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$13,315	$13,315	$10,441	$8,669	$8,531	$7,772	$7,814	
Carrying Amount	$11,086	$11,086	$9,357	$8,439	$7,935	$7,276	$7,275	
Adjustment to Book Value of Long-Term	$2,229	$2,229	$1,084	$230	$596	$496	$539	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$14,240	$14,240	$11,365	$9,450	$9,140	$8,405	$7,801	[s] = [q] + [r].
Market Value of Debt	$14,240	$14,240	$11,365	$9,450	$9,140	$8,405	$7,801	[t] = [s].
MARKET VALUE OF FIRM								
	$35,669	$34,569	$29,080	$27,423	$22,535	$21,774	$19,669	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	60.08%	58.81%	60.92%	65.54%	59.44%	61.40%	60.34%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	39.92%	41.19%	39.08%	34.46%	40.56%	38.60%	39.66%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel E: Avista Corp.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equit	$2,030	$2,030	$1,959	$1,867	$1,758	$1,686	$1,590	[a]
Shares Outstanding (in millions) - Commo	69	69	67	66	66	64	63	[b]
Price per Share - Common	$47	$46	$43	$41	$51	$39	$40	[c]
Market Value of Common Equity	$3,244	$3,217	$2,875	$2,690	$3,355	$2,528	$2,525	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,244	$3,217	$2,875	$2,690	$3,355	$2,528	$2,525	[f]= [d] + [e]
Market to Book Value of Common Equity	1.60	1.58	1.47	1.44	1.91	1.50	1.59	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$344	$344	$274	$365	$310	$357	$279	[j]
Current Liabilities	$506	$506	$566	$567	$670	$367	$432	[k]
Current Portion of Long-Term Debt	$7	$7	$114	$112	$275	$3	$93	[l]
Net Working Capital	($155)	($155)	($177)	($90)	($85)	($6)	($59)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$203	$203	$185	$119	$50	$105	$90	[n]
Adjusted Short-Term Debt	$155	$155	$177	$90	$50	$6	$59	[o] = See Sources and Notes.
Long-Term Debt	$2,177	$2,177	$1,958	$1,874	$1,543	$1,730	$1,531	[p]
Book Value of Long-Term Debt	$2,339	$2,339	$2,249	$2,076	$1,868	$1,739	$1,684	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,190	$1,190	$1,125	$1,142	$1,068	$1,049	$1,056	
Carrying Amount	$964	$964	$964	$1,054	$951	$951	$951	
Adjustment to Book Value of Long-Ter	$226	$226	$161	$89	$117	$98	$105	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,565	$2,565	$2,410	$2,165	$1,985	$1,837	$1,789	[s] = [q] + [r].
Market Value of Debt	$2,565	$2,565	$2,410	$2,165	$1,985	$1,837	$1,789	[t] = [s].
MARKET VALUE OF FIRM	$5,809	$5,782	$5,285	$4,855	$5,339	$4,365	$4,313	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	55.85%	55.64%	54.39%	55.41%	62.83%	57.92%	58.53%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	44.15%	44.36%	45.61%	44.59%	37.17%	42.08%	41.47%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
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Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel F: Black Hills

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$2,625	$2,625	$2,523	$2,279	$1,819	$1,674	$1,481	[a]
Shares Outstanding (in millions) - Common	63	63	63	60	54	53	51	[b]
Price per Share - Common	$70	$66	$59	$73	$53	$66	$59	[c]
Market Value of Common Equity	$4,370	$4,159	$3,730	$4,410	$2,836	$3,526	$3,035	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$4,370	$4,159	$3,730	$4,410	$2,836	$3,526	$3,035	[f]= [d] + [e]
Market to Book Value of Common Equity	1.66	1.58	1.48	1.93	1.56	2.11	2.05	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$579	$579	$490	$485	$492	$401	$402	[j]
Current Liabilities	$1,230	$1,230	$720	$591	$789	$392	$639	[k]
Current Portion of Long-Term Debt	$7	$7	$6	$7	$256	$6	$0	[l]
Net Working Capital	($644)	($644)	($224)	($100)	($41)	$16	($237)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$816	$816	$319	$165	$164	$51	$216	[n]
Adjusted Short-Term Debt	$644	$644	$224	$100	$41	$0	$216	[o] = See Sources and Notes.
Long-Term Debt	$3,529	$3,529	$3,137	$2,955	$2,859	$3,211	$3,159	[p]
Book Value of Long-Term Debt	$4,180	$4,180	$3,367	$3,062	$3,155	$3,216	$3,375	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$4,208	$4,208	$3,479	$3,039	$3,351	$3,351	$1,992	
Carrying Amount	$3,537	$3,537	$3,146	$2,957	$3,115	$3,217	$1,854	
Adjustment to Book Value of Long-Term	$672	$672	$334	$83	$235	$134	$139	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$4,852	$4,852	$3,701	$3,144	$3,391	$3,351	$3,513	[s] = [q] + [r].
Market Value of Debt	$4,852	$4,852	$3,701	$3,144	$3,391	$3,351	$3,513	[t] = [s].
MARKET VALUE OF FIRM	$9,221	$9,011	$7,431	$7,554	$6,226	$6,877	$6,548	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	47.39%	46.15%	50.20%	58.38%	45.54%	51.27%	46.35%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	52.61%	53.85%	49.80%	41.62%	54.46%	48.73%	53.65%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
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[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel G: CMS Energy Corp.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equi	$5,727	$5,727	$5,185	$4,858	$4,596	$4,370	$4,109	[a]
Shares Outstanding (in millions) - Commo	290	290	286	284	283	280	279	[b]
Price per Share - Common	$64	$59	$57	$55	$44	$45	$42	[c]
Market Value of Common Equity	$18,403	$17,207	$16,449	$15,700	$12,395	$12,540	$11,591	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$18,403	$17,207	$16,449	$15,700	$12,395	$12,540	$11,591	[f]= [d] + [e]
Market to Book Value of Common Equity	3.21	3.00	3.17	3.23	2.70	2.87	2.82	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,513	$2,513	$2,817	$2,376	$2,207	$2,215	$1,890	[j]
Current Liabilities	$2,885	$2,885	$2,940	$2,106	$2,482	$1,926	$2,047	[k]
Current Portion of Long-Term Debt	$1,506	$1,506	$1,721	$852	$1,286	$812	$950	[l]
Net Working Capital	$1,134	$1,134	$1,598	$1,122	$1,011	$1,101	$793	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$30	$0	$0	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$13,612	$13,612	$12,616	$11,240	$9,082	$9,233	$8,284	[p]
Book Value of Long-Term Debt	$15,118	$15,118	$14,337	$12,092	$10,368	$10,045	$9,234	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Deb	$17,512	$17,512	$14,185	$11,630	$10,715	$9,953	$9,599	
Carrying Amount	$15,120	$15,120	$13,062	$11,589	$10,204	$9,504	$9,125	
Adjustment to Book Value of Long-Te	$2,392	$2,392	$1,123	$41	$511	$449	$474	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$17,510	$17,510	$15,460	$12,133	$10,879	$10,494	$9,708	[s] = [q] + [r].
Market Value of Debt	$17,510	$17,510	$15,460	$12,133	$10,879	$10,494	$9,708	[t] = [s].
MARKET VALUE OF FIRM								
	$35,913	$34,717	$31,909	$27,833	$23,274	$23,034	$21,299	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	51.24%	49.56%	51.55%	56.41%	53.26%	54.44%	54.42%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	48.76%	50.44%	48.45%	43.59%	46.74%	45.56%	45.58%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel H: CenterPoint Energy

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$6,353	$6,353	$6,970	$6,476	$4,857	$3,537	$3,506	[a]
Shares Outstanding (in millions) - Common	552	552	503	502	431	431	431	[b]
Price per Share - Common	$24	$22	$14	$31	$27	$28	$21	[c]
Market Value of Common Equity	$13,251	$12,240	$7,275	$15,349	$11,653	$11,932	$8,943	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$13,251	$12,240	$7,275	$15,349	$11,653	$11,932	$8,943	[f]= [d] + [e]
Market to Book Value of Common Equity	2.09	1.93	1.04	2.37	2.40	3.37	2.55	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$2,363	$2,363	$1,740	$1,740	$0	$0	$0	[h]
Market Value of Preferred Equity	$2,363	$2,363	$1,740	$1,740	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,219	$3,219	$4,164	$3,419	$3,049	$2,896	$2,335	[j]
Current Liabilities	$4,326	$4,326	$4,042	$3,139	$2,616	$2,642	$2,534	[k]
Current Portion of Long-Term Debt	$1,788	$1,788	$1,426	$420	$613	$787	$1,124	[l]
Net Working Capital	$681	$681	$1,548	$700	$1,046	$1,041	$925	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$927	$927	$893	$687	$674	$727	$498	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$14,048	$14,048	$13,830	$13,808	$8,176	$7,892	$7,354	[p]
Book Value of Long-Term Debt	$15,836	$15,836	$15,256	$14,228	$8,789	$8,679	$8,478	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$15,226	$15,226	$16,067	$9,140	$8,679	$5,079	$0	
Carrying Amount	$13,401	$13,401	$15,093	$9,308	$9,220	$4,865	$0	
Adjustment to Book Value of Long-Term	$1,825	$1,825	$974	($168)	($541)	$214	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$17,661	$17,661	$16,230	$14,060	$8,248	$8,893	$8,478	[s] = [q] + [r].
Market Value of Debt	$17,661	$17,661	$16,230	$14,060	$8,248	$8,893	$8,478	[t] = [s].
MARKET VALUE OF FIRM								
	$33,275	$32,264	$25,245	$31,149	$19,901	$20,825	$17,421	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	39.82%	37.94%	28.82%	49.28%	58.55%	57.30%	51.33%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	7.10%	7.32%	6.89%	5.59%	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	53.08%	54.74%	64.29%	45.14%	41.45%	42.70%	48.67%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel I: Consol. Edison

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$19,033	$19,033	$18,261	$17,369	$15,654	$14,498	$13,193	[a]
Shares Outstanding (in millions) - Common	342	342	334	327	311	305	294	[b]
Price per Share - Common	$77	$73	$80	$85	$77	$77	$75	[c]
Market Value of Common Equity	$26,397	$24,921	$26,631	$27,705	$23,821	$23,624	$22,038	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$26,397	$24,921	$26,631	$27,705	$23,821	$23,624	$22,038	[f]= [d] + [e]
Market to Book Value of Common Equity	1.39	1.31	1.46	1.60	1.52	1.63	1.67	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,587	$4,587	$5,026	$3,781	$3,773	$3,017	$3,185	[j]
Current Liabilities	$6,559	$6,559	$6,311	$6,348	$5,651	$3,441	$4,436	[k]
Current Portion of Long-Term Debt	$1,875	$1,875	$2,170	$2,080	$1,291	$33	$739	[l]
Net Working Capital	($97)	($97)	$885	($487)	($587)	($391)	($512)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,581	$1,581	$1,208	$1,435	$1,389	$836	$1,199	[n]
Adjusted Short-Term Debt	$97	$97	$0	$487	$587	$391	$512	[o] = See Sources and Notes.
Long-Term Debt	$21,379	$21,379	$20,223	$17,759	$14,730	$14,829	$12,222	[p]
Book Value of Long-Term Debt	$23,351	$23,351	$22,393	$20,326	$16,608	$15,253	$13,473	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$26,808	$26,808	$22,738	$18,740	$18,147	$16,093	$13,856	
Carrying Amount	$22,349	$22,349	$19,973	$18,145	$16,029	$14,774	$12,745	
Adjustment to Book Value of Long-Term	$4,459	$4,459	$2,765	$595	$2,118	$1,319	$1,111	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$27,810	$27,810	$25,158	$20,921	$18,726	$16,572	$14,584	[s] = [q] + [r].
Market Value of Debt	$27,810	$27,810	$25,158	$20,921	$18,726	$16,572	$14,584	[t] = [s].
MARKET VALUE OF FIRM	$54,207	$52,731	$51,789	$48,626	$42,547	$40,196	$36,622	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	48.70%	47.26%	51.42%	56.98%	55.99%	58.77%	60.18%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	51.30%	52.74%	48.58%	43.02%	44.01%	41.23%	39.82%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel J: DTE Energy

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$12,552	$12,552	$11,822	$10,545	$9,888	$9,194	$8,887	[a]
Shares Outstanding (in millions) - Common	194	194	193	183	181	179	179	[b]
Price per Share - Common	$139	$130	$90	$124	$102	$101	$89	[c]
Market Value of Common Equity	$26,858	$25,278	$17,390	$22,731	$18,547	$18,188	$16,008	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$26,858	$25,278	$17,390	$22,731	$18,547	$18,188	$16,008	[f]= [d] + [e]
Market to Book Value of Common Equity	2.14	2.01	1.47	2.16	1.88	1.98	1.80	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,376	$4,376	$3,526	$2,840	$2,957	$2,567	$2,362	[j]
Current Liabilities	$2,595	$2,595	$3,972	$3,647	$2,541	$1,834	$2,209	[k]
Current Portion of Long-Term Debt	$502	$502	$419	$1,532	$106	$13	$462	[l]
Net Working Capital	$2,283	$2,283	($27)	$725	$522	$746	$615	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$52	$52	$1,131	$156	$635	$59	$365	[n]
Adjusted Short-Term Debt	$0	$0	$27	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$20,098	$20,098	$17,150	$12,874	$12,185	$11,758	$8,758	[p]
Book Value of Long-Term Debt	$20,600	$20,600	$17,596	$14,406	$12,291	$11,771	$9,220	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$18,031	$18,031	$18,031	$13,825	$13,274	$11,905	$9,835	
Carrying Amount	$19,439	$19,439	$16,606	$13,622	$12,288	$11,270	$9,285	
Adjustment to Book Value of Long-Term Debt	($1,408)	($1,408)	$1,425	$203	$986	$635	$550	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$19,192	$19,192	$19,021	$14,609	$13,277	$12,406	$9,770	[s] = [q] + [r].
Market Value of Debt	$19,192	$19,192	$19,021	$14,609	$13,277	$12,406	$9,770	[t] = [s].
MARKET VALUE OF FIRM								
	$46,050	$44,470	$36,411	$37,340	$31,824	$30,594	$25,778	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.32%	56.84%	47.76%	60.88%	58.28%	59.45%	62.10%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	41.68%	43.16%	52.24%	39.12%	41.72%	40.55%	37.90%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
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Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel K: Duke Energy

($MM)

	DCF Capital	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$46,224	$46,224	$44,959	$44,056	$41,792	$41,179	$39,892	[a]
Shares Outstanding (in millions) - Common	769	769	735	728	701	700	689	[b]
Price per Share - Common	$100	$94	$79	$90	$77	$82	$79	[c]
Market Value of Common Equity	$76,623	$72,162	$57,750	$65,703	$53,715	$57,478	$54,583	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$76,623	$72,162	$57,750	$65,703	$53,715	$57,478	$54,583	[f]= [d] + [e]
Market to Book Value of Common Equity	1.66	1.56	1.28	1.49	1.29	1.40	1.37	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$1,962	$1,962	$1,962	$974	$0	$0	$0	[h]
Market Value of Preferred Equity	$1,962	$1,962	$1,962	$974	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$8,508	$8,508	$10,181	$9,168	$8,279	$8,005	$7,943	[j]
Current Liabilities	$17,333	$17,333	$15,170	$12,282	$12,998	$10,941	$10,891	[k]
Current Portion of Long-Term Debt	$5,586	$5,586	$5,077	$2,805	$3,951	$1,977	$2,075	[l]
Net Working Capital	($3,239)	($3,239)	$88	($309)	($768)	($959)	($873)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$4,064	$4,064	$3,033	$3,029	$2,969	$3,558	$3,486	[n]
Adjusted Short-Term Debt	$3,239	$3,239	$0	$309	$768	$959	$873	[o] = See Sources and Notes.
Long-Term Debt	$56,120	$56,120	$57,725	$55,169	$49,030	$47,021	$38,232	[p]
Book Value of Long-Term Debt	$64,945	$64,945	$62,802	$58,283	$53,749	$49,957	$41,180	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$69,292	$69,292	$63,062	$54,534	$55,331	$49,161	$0	
Carrying Amount	$59,863	$59,863	$58,126	$54,529	$52,279	$47,895	$0	
Adjustment to Book Value of Long-Term	$9,429	$9,429	$4,936	$5	$3,052	$1,266	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$74,374	$74,374	$67,738	$58,288	$56,801	$51,223	$41,180	[s] = [q] + [r].
Market Value of Debt	$74,374	$74,374	$67,738	$58,288	$56,801	$51,223	$41,180	[t] = [s].
MARKET VALUE OF FIRM	$152,959	$148,498	$127,450	$124,965	$110,516	$108,701	$95,763	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	50.09%	48.59%	45.31%	52.58%	48.60%	52.88%	57.00%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	1.28%	1.32%	1.54%	0.78%	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	48.62%	50.08%	53.15%	46.64%	51.40%	47.12%	43.00%	[x] = [t] / [u].

Sources and Notes:
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[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel L: Edison Int'l

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$14,085	$14,085	$13,351	$10,526	$11,696	$12,051	$11,439	[a]
Shares Outstanding (in millions) - Common	379	379	363	326	326	326	326	[b]
Price per Share - Common	$60	$59	$52	$64	$63	$80	$71	[c]
Market Value of Common Equity	$22,781	$22,514	$18,912	$20,767	$20,423	$25,968	$23,152	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$22,781	$22,514	$18,912	$20,767	$20,423	$25,968	$23,152	[f]= [d] + [e]
Market to Book Value of Common Equity	1.62	1.60	1.42	1.97	1.75	2.15	2.02	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$3,138	$3,138	$2,193	$2,193	$2,193	$2,191	$2,192	[h]
Market Value of Preferred Equity	$3,138	$3,138	$2,193	$2,193	$2,193	$2,191	$2,192	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$5,328	$5,328	$4,911	$3,999	$2,992	$2,046	$2,427	[j]
Current Liabilities	$9,497	$9,497	$6,248	$5,375	$4,647	$4,416	$4,233	[k]
Current Portion of Long-Term Debt	$1,124	$1,124	$975	$237	$479	$981	$295	[l]
Net Working Capital	($3,045)	($3,045)	($362)	($1,139)	($1,176)	($1,389)	($1,511)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$2,520	$2,520	$1,275	$932	$70	$295	$363	[n]
Adjusted Short-Term Debt	$2,520	$2,520	$362	$932	$70	$295	$363	[o] = See Sources and Notes.
Long-Term Debt	$21,021	$21,021	$19,734	$16,468	$13,367	$11,662	$11,243	[p]
Book Value of Long-Term Debt	$24,665	$24,665	$21,071	$17,637	$13,916	$12,938	$11,901	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$23,824	$23,824	$20,137	$14,844	$13,760	$12,368	$12,252	
Carrying Amount	$20,337	$20,337	$18,343	$14,711	$12,123	$11,156	$11,259	
Adjustment to Book Value of Long-Term	$3,487	$3,487	$1,794	$133	$1,637	$1,212	$993	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$28,152	$28,152	$22,865	$17,770	$15,553	$14,150	$12,894	[s] = [q] + [r].
Market Value of Debt	$28,152	$28,152	$22,865	$17,770	$15,553	$14,150	$12,894	[t] = [s].
MARKET VALUE OF FIRM	$54,071	$53,804	$43,970	$40,730	$38,169	$42,309	$38,238	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	42.13%	41.84%	43.01%	50.99%	53.51%	61.38%	60.55%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	5.80%	5.83%	4.99%	5.38%	5.75%	5.18%	5.73%	[w] = [i] / [u].
Debt - Market Value Ratio	52.06%	52.32%	52.00%	43.63%	40.75%	33.44%	33.72%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel M: Entergy Corp.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$11,017	$11,017	$10,224	$8,970	$7,975	$8,057	$9,361	[a]
Shares Outstanding (in millions) - Common	201	201	200	190	181	179	179	[b]
Price per Share - Common	$106	$98	$93	$95	$78	$76	$78	[c]
Market Value of Common Equity	$21,339	$19,647	$18,609	$18,039	$14,120	$13,582	$13,932	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$21,339	$19,647	$18,609	$18,039	$14,120	$13,582	$13,932	[f]= [d] + [e]
Market to Book Value of Common Equity	1.94	1.78	1.82	2.01	1.77	1.69	1.49	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$254	$254	$254	$219	$198	$203	$318	[h]
Market Value of Preferred Equity	$254	$254	$254	$219	$198	$203	$318	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,789	$4,789	$3,974	$3,408	$3,656	$3,397	$4,001	[j]
Current Liabilities	$4,512	$4,512	$6,018	$4,861	$5,233	$3,879	$3,839	[k]
Current Portion of Long-Term Debt	$629	$629	$1,230	$215	$1,261	$336	$799	[l]
Net Working Capital	$906	$906	($814)	($1,239)	($316)	($145)	$961	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,028	$1,028	$1,942	$1,942	$805	$1,323	$766	[n]
Adjusted Short-Term Debt	$0	$0	$814	$1,239	$316	$145	$0	[o] = See Sources and Notes.
Long-Term Debt	$24,075	$24,075	$18,229	$17,394	$15,613	$13,951	$13,526	[p]
Book Value of Long-Term Debt	$24,704	$24,704	$20,273	$18,848	$17,190	$14,432	$14,326	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$24,814	$24,814	$19,060	$15,880	$15,367	$14,816	$13,579	
Carrying Amount	$22,370	$22,370	$17,874	$16,168	$15,075	$14,833	$13,326	
Adjustment to Book Value of Long-Term	$2,444	$2,444	$1,186	($288)	$292	($17)	$253	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$27,149	$27,149	$21,459	$18,560	$17,482	$14,415	$14,579	[s] = [q] + [r].
Market Value of Debt	$27,149	$27,149	$21,459	$18,560	$17,482	$14,415	$14,579	[t] = [s].
MARKET VALUE OF FIRM	$48,742	$47,049	$40,322	$36,818	$31,800	$28,200	$28,829	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	43.78%	41.76%	46.15%	48.99%	44.40%	48.16%	48.33%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.52%	0.54%	0.63%	0.60%	0.62%	0.72%	1.10%	[w] = [i] / [u].
Debt - Market Value Ratio	55.70%	57.70%	53.22%	50.41%	54.98%	51.12%	50.57%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel N: Evergy Inc.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$8,806	$8,806	$8,529	$9,423	#N/A N/A	#N/A N/A	#N/A N/A	[a]
Shares Outstanding (in millions) - Common	227	227	227	245	#N/A N/A	#N/A N/A	#N/A N/A	[b]
Price per Share - Common	$63	$59	$55	$57	$51	$55	$48	[c]
Market Value of Common Equity	$14,316	$13,384	$12,424	$14,043	N/A	N/A	N/A	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$14,316	$13,384	$12,424	$14,043	N/A	N/A	N/A	[f]= [d] + [e]
Market to Book Value of Common Equity	1.63	1.52	1.46	1.49	N/A	N/A	N/A	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,002	$2,002	$1,733	$1,928	#N/A N/A	#N/A N/A	#N/A N/A	[j]
Current Liabilities	$3,244	$3,244	$2,398	$3,335	#N/A N/A	#N/A N/A	#N/A N/A	[k]
Current Portion of Long-Term Debt	$534	$534	$20	$750	$0	$0	$0	[l]
Net Working Capital	($708)	($708)	($645)	($658)	N/A	N/A	N/A	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,660	$1,660	$1,377	$1,670	#N/A N/A	#N/A N/A	#N/A N/A	[n]
Adjusted Short-Term Debt	$708	$708	$645	$658	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$9,119	$9,119	$8,994	$7,232	#N/A N/A	#N/A N/A	#N/A N/A	[p]
Book Value of Long-Term Debt	$10,361	$10,361	$9,658	$8,639	N/A	N/A	N/A	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$11,274	$11,274	$9,750	$7,412	$4,011	$0	$0	
Carrying Amount	$9,627	$9,627	$8,998	$7,342	$3,688	$0	$0	
Adjustment to Book Value of Long-Tern	$1,647	$1,647	$752	$70	$323	$0	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$12,008	$12,008	$10,411	$8,710	N/A	N/A	N/A	[s] = [q] + [r].
Market Value of Debt	$12,008	$12,008	$10,411	$8,710	N/A	N/A	N/A	[t] = [s].
MARKET VALUE OF FIRM	$26,324	$25,392	$22,835	$22,753	N/A	N/A	N/A	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	54.38%	52.71%	54.41%	61.72%	N/A	N/A	N/A	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	N/A	N/A	N/A	[w] = [i] / [u].
Debt - Market Value Ratio	45.62%	47.29%	45.59%	38.28%	N/A	N/A	N/A	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel O: Eversource Energy

($MM)

	DCF Capital	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$14,233	$14,233	$13,210	$11,637	$11,184	$10,804	$10,438	[a]
Shares Outstanding (in millions) - Common	343	343	336	317	317	317	317	[b]
Price per Share - Common	$88	$84	$79	$71	$58	$59	$58	[c]
Market Value of Common Equity	$30,174	$28,799	$26,511	$22,521	$18,274	$18,713	$18,241	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$30,174	$28,799	$26,511	$22,521	$18,274	$18,713	$18,241	[f]= [d] + [e]
Market to Book Value of Common Equity	2.12	2.02	2.01	1.94	1.63	1.73	1.75	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$156	$156	$156	$156	$156	$156	$156	[h]
Market Value of Preferred Equity	$156	$156	$156	$156	$156	$156	$156	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,147	$3,147	$2,563	$2,301	$2,771	$2,511	$2,591	[j]
Current Liabilities	$5,539	$5,539	$3,396	$4,559	$4,096	$3,334	$2,594	[k]
Current Portion of Long-Term Debt	$1,211	$1,211	$532	$817	$1,097	$774	$379	[l]
Net Working Capital	($1,181)	($1,181)	($301)	($1,442)	($227)	($48)	$376	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,872	$1,872	$661	$1,478	$1,049	$976	$770	[n]
Adjusted Short-Term Debt	$1,181	$1,181	$301	$1,442	$227	$48	$0	[o] = See Sources and Notes.
Long-Term Debt	$14,783	$14,783	$13,899	$12,293	$12,016	$9,268	$9,145	[p]
Book Value of Long-Term Debt	$17,175	$17,175	$14,732	$14,552	$13,341	$10,090	$9,524	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$18,420	$18,420	$15,170	$13,155	$12,877	$9,981	$9,426	
Carrying Amount	$16,179	$16,179	$14,098	$13,086	$12,326	$9,603	$9,035	
Adjustment to Book Value of Long-Term	$2,241	$2,241	$1,072	$69	$552	$377	$391	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$19,416	$19,416	$15,804	$14,621	$13,892	$10,468	$9,915	[s] = [q] + [r].
Market Value of Debt	$19,416	$19,416	$15,804	$14,621	$13,892	$10,468	$9,915	[t] = [s].
MARKET VALUE OF FIRM	$49,745	$48,371	$42,471	$37,298	$32,321	$29,336	$28,312	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	60.66%	59.54%	62.42%	60.38%	56.54%	63.79%	64.43%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.31%	0.32%	0.37%	0.42%	0.48%	0.53%	0.55%	[w] = [i] / [u].
Debt - Market Value Ratio	39.03%	40.14%	37.21%	39.20%	42.98%	35.68%	35.02%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel P: Exelon Corp.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equi	$32,015	$32,015	$32,482	$31,357	$30,231	$26,530	$25,717	[a]
Shares Outstanding (in millions) - Comm	977	977	974	971	965	926	922	[b]
Price per Share - Common	$45	$43	$35	$50	$38	$36	$35	[c]
Market Value of Common Equity	$44,153	$42,102	$33,737	$48,360	$36,757	$33,270	$32,275	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$44,153	$42,102	$33,737	$48,360	$36,757	$33,270	$32,275	[f]= [d] + [e]
Market to Book Value of Common Equity	1.38	1.32	1.04	1.54	1.22	1.25	1.25	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$193	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$193	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$12,997	$12,997	$12,476	$12,476	$11,533	$12,194	$11,364	[j]
Current Liabilities	$13,580	$13,580	$11,774	$12,229	$10,153	$14,437	$13,770	[k]
Current Portion of Long-Term Debt	$2,281	$2,281	$2,848	$2,757	$1,203	$3,645	$2,058	[l]
Net Working Capital	$1,698	$1,698	$3,550	$3,004	$2,583	$1,402	($348)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$3,128	$3,128	$1,979	$1,254	$1,654	$2,048	$3,640	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$348	[o] = See Sources and Notes.
Long-Term Debt	$36,638	$36,638	$35,198	$34,745	$33,294	$31,685	$29,955	[p]
Book Value of Long-Term Debt	$38,919	$38,919	$38,046	$37,502	$34,497	$35,330	$32,361	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Deb	$43,752	$43,752	$40,033	$35,869	$36,705	$34,813	$25,924	
Carrying Amount	$36,912	$36,912	$36,039	$35,424	$34,264	$34,005	$25,145	
Adjustment to Book Value of Long-Te	$6,840	$6,840	$3,994	$445	$2,441	$808	$779	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$45,759	$45,759	$42,040	$37,947	$36,938	$36,138	$33,140	[s] = [q] + [r].
Market Value of Debt	$45,759	$45,759	$42,040	$37,947	$36,938	$36,138	$33,140	[t] = [s].
MARKET VALUE OF FIRM	$89,912	$87,861	$75,777	$86,307	$73,695	$69,408	$65,608	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	49.11%	47.92%	44.52%	56.03%	49.88%	47.93%	49.19%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	0.29%	[w] = [i] / [u].
Debt - Market Value Ratio	50.89%	52.08%	55.48%	43.97%	50.12%	52.07%	50.51%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
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[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel Q: IDACORP Inc.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equ	$2,569	$2,569	$2,467	$2,380	$2,257	$2,159	$2,058	[a]
Shares Outstanding (in millions) - Comm	51	51	50	50	50	50	50	[b]
Price per Share - Common	$101	$99	$86	$100	$85	$82	$74	[c]
Market Value of Common Equity	$5,088	$5,021	$4,344	$5,027	$4,295	$4,143	$3,731	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$5,088	$5,021	$4,344	$5,027	$4,295	$4,143	$3,731	[f]= [d] + [e]
Market to Book Value of Common Equit	1.98	1.95	1.76	2.11	1.90	1.92	1.81	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$594	$594	$473	$576	$638	$409	$587	[j]
Current Liabilities	$262	$262	$248	$273	$332	$181	$312	[k]
Current Portion of Long-Term Debt	$0	$0	$0	$0	$130	$0	$101	[l]
Net Working Capital	$332	$332	$225	$303	$436	$228	$377	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$0	$0	$0	$23	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$2,000	$2,000	$1,837	$1,835	$1,834	$1,745	$1,744	[p]
Book Value of Long-Term Debt	$2,000	$2,000	$1,837	$1,835	$1,964	$1,745	$1,845	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Del	$2,467	$2,467	$2,084	$1,943	$1,915	$1,859	$1,813	
Carrying Amount	$2,000	$2,000	$1,837	$1,835	$1,746	$1,746	$1,726	
Adjustment to Book Value of Long-Te	$467	$467	$247	$108	$169	$113	$87	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,467	$2,467	$2,084	$1,943	$2,133	$1,858	$1,932	[s] = [q] + [r].
Market Value of Debt	$2,467	$2,467	$2,084	$1,943	$2,133	$1,858	$1,932	[t] = [s].
MARKET VALUE OF FIRM	$7,555	$7,488	$6,428	$6,970	$6,428	$6,001	$5,664	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	67.35%	67.06%	67.58%	72.12%	66.82%	69.04%	65.88%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	32.65%	32.94%	32.42%	27.88%	33.18%	30.96%	34.12%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel R: MGE Energy

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equit	$998	$998	$869	$829	$787	$733	$697	[a]
Shares Outstanding (in millions) - Commo	36	36	35	35	35	35	35	[b]
Price per Share - Common	$74	$71	$63	$66	$56	$63	$51	[c]
Market Value of Common Equity	$2,681	$2,584	$2,194	$2,295	$1,929	$2,194	$1,759	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$2,681	$2,584	$2,194	$2,295	$1,929	$2,194	$1,759	[f]= [d] + [e]
Market to Book Value of Common Equity	2.69	2.59	2.52	2.77	2.45	2.99	2.52	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$202	$202	$162	$221	$249	$254	$247	[j]
Current Liabilities	$184	$184	$111	$112	$106	$84	$118	[k]
Current Portion of Long-Term Debt	$5	$5	$20	$5	$24	$4	$34	[l]
Net Working Capital	$23	$23	$71	$113	$167	$175	$164	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$54	$54	$3	$6	$3	$0	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$536	$536	$540	$510	$397	$391	$356	[p]
Book Value of Long-Term Debt	$541	$541	$560	$515	$422	$396	$390	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$639	$639	$612	$519	$475	$430	$436	
Carrying Amount	$528	$528	$548	$502	$427	$391	$396	
Adjustment to Book Value of Long-Ter	$111	$111	$64	$16	$48	$39	$40	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$652	$652	$624	$531	$470	$435	$430	[s] = [q] + [r].
Market Value of Debt	$652	$652	$624	$531	$470	$435	$430	[t] = [s].
MARKET VALUE OF FIRM								
	$3,332	$3,236	$2,817	$2,826	$2,399	$2,629	$2,189	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	80.44%	79.86%	77.86%	81.21%	80.41%	83.46%	80.34%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	19.56%	20.14%	22.14%	18.79%	19.59%	16.54%	19.66%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel S: NextEra Energy

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$37,378	$37,378	$36,403	$34,226	$32,706	$25,497	$22,912	[a]
Shares Outstanding (in millions) - Common	1,961	1,961	489	479	471	468	461	[b]
Price per Share - Common	$79	$74	$54	$48	$40	$33	$29	[c]
Market Value of Common Equity	$154,110	$144,727	$26,508	$22,963	$18,781	$15,300	$13,531	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$154,110	$144,727	$26,508	$22,963	$18,781	$15,300	$13,531	[f]= [d] + [e]
Market to Book Value of Common Equity	4.12	3.87	0.73	0.67	0.57	0.60	0.59	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$8,237	$8,237	$9,725	$8,222	$5,612	$5,827	$7,096	[j]
Current Liabilities	$15,783	$15,783	$13,722	$17,926	$9,579	$9,761	$10,587	[k]
Current Portion of Long-Term Debt	$3,837	$3,837	$2,489	$2,614	$1,168	$2,766	$2,145	[l]
Net Working Capital	($3,709)	($3,709)	($1,508)	($7,090)	($2,799)	($1,168)	($1,346)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$2,766	$2,766	$3,601	$7,716	$2,969	$2,559	$2,472	[n]
Adjusted Short-Term Debt	$2,766	$2,766	$1,508	$7,090	$2,799	$1,168	$1,346	[o] = See Sources and Notes.
Long-Term Debt	$46,065	$46,065	$41,116	$29,883	$28,062	$28,539	$27,791	[p]
Book Value of Long-Term Debt	$52,668	$52,668	$45,113	$39,587	$32,029	$32,473	$31,282	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$51,525	$51,525	$42,928	$30,043	$35,447	$31,623	$30,412	
Carrying Amount	$46,082	$46,082	$39,667	$29,498	$33,134	$30,418	$28,897	
Adjustment to Book Value of Long-Term	$5,443	$5,443	$3,261	$545	$2,313	$1,205	$1,515	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$58,111	$58,111	$48,374	$40,132	$34,342	$33,678	$32,797	[s] = [q] + [r].
Market Value of Debt	$58,111	$58,111	$48,374	$40,132	$34,342	$33,678	$32,797	[t] = [s].
MARKET VALUE OF FIRM								
	$212,221	$202,838	$74,882	$63,095	$53,123	$48,978	$46,328	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	72.62%	71.35%	35.40%	36.39%	35.35%	31.24%	29.21%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	27.38%	28.65%	64.60%	63.61%	64.65%	68.76%	70.79%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel T: NorthWestern Corp.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equi	$2,114	$2,114	$2,060	$1,990	$1,835	$1,709	$1,615	[a]
Shares Outstanding (in millions) - Commc	54	54	54	54	53	52	52	[b]
Price per Share - Common	$68	$64	$58	$71	$52	$58	$61	[c]
Market Value of Common Equity	$3,696	$3,470	$3,162	$3,808	$2,760	$3,031	$3,156	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,696	$3,470	$3,162	$3,808	$2,760	$3,031	$3,156	[f]= [d] + [e]
Market to Book Value of Common Equity	1.75	1.64	1.53	1.91	1.50	1.77	1.95	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$359	$359	$330	$288	$258	$245	$250	[j]
Current Liabilities	$386	$386	$348	$347	$326	$545	$518	[k]
Current Portion of Long-Term Debt	$3	$3	$3	$2	$2	$2	$2	[l]
Net Working Capital	($25)	($25)	($15)	($57)	($66)	($298)	($266)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$0	$0	$229	$162	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$229	$162	[o] = See Sources and Notes.
Long-Term Debt	$2,478	$2,478	$2,256	$2,100	$2,038	$1,817	$1,794	[p]
Book Value of Long-Term Debt	$2,481	$2,481	$2,259	$2,102	$2,040	$2,048	$1,958	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Deb	$2,630	$2,630	$2,417	$2,118	$1,902	$1,852	$1,845	
Carrying Amount	$2,315	$2,315	$2,233	$2,102	$1,793	$1,793	$1,782	
Adjustment to Book Value of Long-Te	$314	$314	$184	$16	$108	$59	$63	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,795	$2,795	$2,442	$2,118	$2,149	$2,107	$2,021	[s] = [q] + [r].
Market Value of Debt	$2,795	$2,795	$2,442	$2,118	$2,149	$2,107	$2,021	[t] = [s].
MARKET VALUE OF FIRM								
	$6,492	$6,265	$5,605	$5,926	$4,909	$5,139	$5,177	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.94%	55.38%	56.43%	64.27%	56.23%	58.99%	60.97%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	43.06%	44.62%	43.57%	35.73%	43.77%	41.01%	39.03%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel U: OGE Energy

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$3,606	$3,606	$3,553	$3,976	$3,842	$3,444	$3,298	[a]
Shares Outstanding (in millions) - Common	200	200	200	200	200	200	200	[b]
Price per Share - Common	$33	$32	$30	$43	$32	$36	$28	[c]
Market Value of Common Equity	$6,636	$6,470	$5,961	$8,591	$6,359	$7,171	$5,576	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$6,636	$6,470	$5,961	$8,591	$6,359	$7,171	$5,576	[f]= [d] + [e]
Market to Book Value of Common Equity	1.84	1.79	1.68	2.16	1.66	2.08	1.69	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$503	$503	$523	$454	$494	$538	$456	[j]
Current Liabilities	$1,837	$1,837	$855	$884	$1,215	$915	$707	[k]
Current Portion of Long-Term Debt	$6	$6	$6	$3	$500	$225	$0	[l]
Net Working Capital	($1,328)	($1,328)	($327)	($428)	($222)	($152)	($251)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,278	$1,278	$375	$366	$194	$128	$188	[n]
Adjusted Short-Term Debt	$1,278	$1,278	$327	$366	$194	$128	$188	[o] = See Sources and Notes.
Long-Term Debt	$3,495	$3,495	$3,196	$2,944	$2,500	$2,703	$2,629	[p]
Book Value of Long-Term Debt	$4,779	$4,779	$3,528	$3,313	$3,194	$3,056	$2,817	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$4,328	$4,328	$3,646	$3,322	$3,388	$2,904	$2,656	
Carrying Amount	$3,494	$3,494	$3,195	$3,147	$2,999	$2,631	$2,899	
Adjustment to Book Value of Long-Term	$834	$834	$451	$175	$389	$273	($244)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$5,613	$5,613	$3,979	$3,488	$3,582	$3,330	$2,573	[s] = [q] + [r].
Market Value of Debt	$5,613	$5,613	$3,979	$3,488	$3,582	$3,330	$2,573	[t] = [s].
MARKET VALUE OF FIRM	$12,249	$12,083	$9,940	$12,079	$9,942	$10,500	$8,149	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	54.18%	53.55%	59.97%	71.12%	63.97%	68.29%	68.42%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	45.82%	46.45%	40.03%	28.88%	36.03%	31.71%	31.58%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
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[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel V: Otter Tail Corp.

($MM)

	DCF Capital	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$888	$888	$800	$740	$708	$679	$614	[a]
Shares Outstanding (in millions) - Common	42	42	40	40	40	39	38	[b]
Price per Share - Common	$47	$46	$41	$50	$43	$37	$28	[c]
Market Value of Common Equity	$1,951	$1,899	$1,655	$1,983	$1,702	$1,460	$1,075	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$1,951	$1,899	$1,655	$1,983	$1,702	$1,460	$1,075	[f]= [d] + [e]
Market to Book Value of Common Equity	2.20	2.14	2.07	2.68	2.40	2.15	1.75	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$259	$259	$256	$274	$240	$219	$210	[j]
Current Liabilities	$459	$459	$176	$201	$166	$236	$233	[k]
Current Portion of Long-Term Debt	$140	$140	$5	$4	$0	$45	$52	[l]
Net Working Capital	($61)	($61)	$85	$77	$74	$28	$29	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$135	$135	$20	$44	$30	$59	$43	[n]
Adjusted Short-Term Debt	$61	$61	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$624	$624	$742	$607	$590	$490	$494	[p]
Book Value of Long-Term Debt	$825	$825	$747	$611	$590	$536	$546	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$858	$858	$742	$602	$543	$584	$563	
Carrying Amount	$765	$765	$690	$590	$491	$539	$498	
Adjustment to Book Value of Long-Term De	$94	$94	$53	$11	$52	$45	$65	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$919	$919	$799	$623	$642	$581	$611	[s] = [q] + [r].
Market Value of Debt	$919	$919	$799	$623	$642	$581	$611	[t] = [s].
MARKET VALUE OF FIRM	$2,870	$2,818	$2,454	$2,605	$2,344	$2,041	$1,686	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	67.98%	67.39%	67.43%	76.10%	72.60%	71.54%	63.75%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	32.02%	32.61%	32.57%	23.90%	27.40%	28.46%	36.25%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel W: Pinnacle West Capital

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equit	$5,683	$5,683	$5,469	$5,251	$5,020	$4,829	$4,600	[a]
Shares Outstanding (in millions) - Commo	113	113	112	112	112	112	111	[b]
Price per Share - Common	$84	$80	$74	$96	$78	$83	$73	[c]
Market Value of Common Equity	$9,451	$9,004	$8,335	$10,727	$8,709	$9,289	$8,110	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$9,451	$9,004	$8,335	$10,727	$8,709	$9,289	$8,110	[f]= [d] + [e]
Market to Book Value of Common Equity	1.66	1.58	1.52	2.04	1.74	1.92	1.76	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,170	$1,170	$1,078	$876	$957	$795	$826	[j]
Current Liabilities	$1,331	$1,331	$2,295	$1,591	$1,874	$1,194	$1,586	[k]
Current Portion of Long-Term Debt	$74	$74	$662	$315	$582	$125	$358	[l]
Net Working Capital	($86)	($86)	($555)	($399)	($335)	($274)	($402)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$215	$215	$563	$244	$370	$207	$262	[n]
Adjusted Short-Term Debt	$86	$86	$555	$244	$335	$207	$262	[o] = See Sources and Notes.
Long-Term Debt	$6,826	$6,826	$4,885	$4,940	$4,291	$4,274	$3,463	[p]
Book Value of Long-Term Debt	$6,986	$6,986	$6,102	$5,499	$5,208	$4,606	$4,082	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$7,613	$7,613	$6,194	$5,234	$5,305	$4,426	$4,106	
Carrying Amount	$6,314	$6,314	$5,633	$5,138	$4,872	$4,147	$3,820	
Adjustment to Book Value of Long-Ter	$1,299	$1,299	$562	$95	$433	$279	$286	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$8,285	$8,285	$6,664	$5,595	$5,641	$4,885	$4,369	[s] = [q] + [r].
Market Value of Debt	$8,285	$8,285	$6,664	$5,595	$5,641	$4,885	$4,369	[t] = [s].
MARKET VALUE OF FIRM								
	$17,736	$17,289	$14,998	$16,321	$14,350	$14,175	$12,479	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	53.29%	52.08%	55.57%	65.72%	60.69%	65.54%	64.99%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	46.71%	47.92%	44.43%	34.28%	39.31%	34.46%	35.01%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel X: Public Serv. Enterprise

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$16,277	$16,277	$15,249	$14,814	$14,104	$13,005	$13,318	[a]
Shares Outstanding (in millions) - Common	504	504	504	504	504	505	505	[b]
Price per Share - Common	$63	$59	$42	$59	$49	$45	$46	[c]
Market Value of Common Equity	$31,642	$29,610	$21,252	$29,917	$24,481	$22,523	$23,085	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$31,642	$29,610	$21,252	$29,917	$24,481	$22,523	$23,085	[f]= [d] + [e]
Market to Book Value of Common Equity	1.94	1.82	1.39	2.02	1.74	1.73	1.73	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,595	$3,595	$3,727	$3,027	$2,806	$2,716	$3,263	[j]
Current Liabilities	$4,546	$4,546	$5,160	$4,473	$3,948	$3,111	$2,910	[k]
Current Portion of Long-Term Debt	$1,429	$1,429	$1,665	$925	$1,000	$500	$562	[l]
Net Working Capital	$478	$478	$232	($521)	($142)	$105	$915	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$665	$665	$1,062	$1,151	$594	$315	$12	[n]
Adjusted Short-Term Debt	$0	$0	$0	$521	$142	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$15,590	$15,590	$14,306	$13,466	$12,072	$10,898	$9,676	[p]
Book Value of Long-Term Debt	$17,019	$17,019	$15,971	$14,912	$13,214	$11,398	$10,238	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$19,143	$19,143	$16,723	$14,767	$14,062	$12,003	$10,256	
Carrying Amount	$16,180	$16,180	$15,108	$14,462	$13,068	$11,395	$9,568	
Adjustment to Book Value of Long-Term	$2,963	$2,963	$1,615	$305	$994	$608	$688	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$19,982	$19,982	$17,586	$15,217	$14,208	$12,006	$10,926	[s] = [q] + [r].
Market Value of Debt	$19,982	$19,982	$17,586	$15,217	$14,208	$12,006	$10,926	[t] = [s].
MARKET VALUE OF FIRM								
	$51,624	$49,592	$38,838	$45,134	$38,689	$34,529	$34,011	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	61.29%	59.71%	54.72%	66.28%	63.28%	65.23%	67.87%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	38.71%	40.29%	45.28%	33.72%	36.72%	34.77%	32.13%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel Y: Sempra Energy

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$22,545	$22,545	$17,859	$15,088	$14,151	$13,264	$11,946	[a]
Shares Outstanding (in millions) - Common	303	303	292	274	264	251	249	[b]
Price per Share - Common	$137	$130	$107	$125	$111	$111	$102	[c]
Market Value of Common Equity	$41,426	$39,444	$31,387	$34,203	$29,273	$27,851	$25,386	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$41,426	$39,444	$31,387	$34,203	$29,273	$27,851	$25,386	[f]= [d] + [e]
Market to Book Value of Common Equity	1.84	1.75	1.76	2.27	2.07	2.10	2.13	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$1,474	$1,474	$2,278	$2,278	$1,713	$20	$20	[h]
Market Value of Preferred Equity	$1,474	$1,474	$2,278	$2,278	$1,713	$20	$20	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,200	$4,200	$5,424	$3,262	$3,394	$2,953	$2,883	[j]
Current Liabilities	$6,875	$6,875	$12,177	$8,612	$9,109	$5,812	$5,132	[k]
Current Portion of Long-Term Debt	$505	$505	$2,079	$2,204	$1,871	$839	$1,066	[l]
Net Working Capital	($2,170)	($2,170)	($4,674)	($3,146)	($3,844)	($2,020)	($1,183)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,817	$1,817	$5,742	$2,523	$3,665	$2,054	$1,177	[n]
Adjusted Short-Term Debt	$1,817	$1,817	$4,674	$2,523	$3,665	$2,020	$1,177	[o] = See Sources and Notes.
Long-Term Debt	$22,023	$22,023	$20,198	$20,193	$21,740	$14,791	$13,361	[p]
Book Value of Long-Term Debt	$24,345	$24,345	$26,951	$24,920	$27,276	$17,650	$15,604	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$25,478	$25,478	$10,003	$7,086	$7,153	$7,153	$7,153	
Carrying Amount	$22,259	$22,259	$8,625	$6,435	$6,117	$6,117	$6,117	
Adjustment to Book Value of Long-Term	$3,219	$3,219	$1,378	$651	$1,036	$1,036	$1,036	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$27,564	$27,564	$28,329	$25,571	$28,312	$18,686	$16,640	[s] = [q] + [r].
Market Value of Debt	$27,564	$27,564	$28,329	$25,571	$28,312	$18,686	$16,640	[t] = [s].
MARKET VALUE OF FIRM								
	$70,464	$68,482	$61,994	$62,052	$59,298	$46,557	$42,046	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.79%	57.60%	50.63%	55.12%	49.37%	59.82%	60.38%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	2.09%	2.15%	3.67%	3.67%	2.89%	0.04%	0.05%	[w] = [i] / [u].
Debt - Market Value Ratio	39.12%	40.25%	45.70%	41.21%	47.75%	40.14%	39.58%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
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Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel Z: Southern Co.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$28,482	$28,482	$27,725	$26,437	$24,676	$25,094	$20,797	[a]
Shares Outstanding (in millions) - Common	1,059	1,059	1,056	1,040	1,012	995	919	[b]
Price per Share - Common	$65	$61	$52	$52	$44	$50	$51	[c]
Market Value of Common Equity	$68,600	$64,403	$55,432	$53,779	$44,500	$49,982	$46,496	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$68,600	$64,403	$55,432	$53,779	$44,500	$49,982	$46,496	[f]= [d] + [e]
Market to Book Value of Common Equity	2.41	2.26	2.00	2.03	1.80	1.99	2.24	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$291	$291	$291	$291	$324	$727	$727	[h]
Market Value of Preferred Equity	$291	$291	$291	$291	$324	$727	$727	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$9,469	$9,469	$9,430	$8,709	$9,524	$8,427	$5,461	[j]
Current Liabilities	$11,586	$11,586	$9,553	$9,919	$13,630	$12,284	$7,856	[k]
Current Portion of Long-Term Debt	$3,779	$3,779	$2,039	$2,541	$3,235	$3,269	$2,392	[l]
Net Working Capital	$1,662	$1,662	$1,916	$1,331	($871)	($588)	($3)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,092	$1,092	$1,710	$1,251	$4,271	$2,818	$1,195	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$871	$588	$3	[o] = See Sources and Notes.
Long-Term Debt	$48,379	$48,379	$45,845	$42,177	$44,446	$42,786	$26,091	[p]
Book Value of Long-Term Debt	$52,158	$52,158	$47,884	$44,718	$48,552	$46,643	$28,486	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$56,264	$56,264	$48,339	$44,824	$51,348	$46,286	$27,913	
Carrying Amount	$48,349	$48,349	$44,561	$45,023	$48,151	$45,080	$27,216	
Adjustment to Book Value of Long-Tern	$7,915	$7,915	$3,778	($199)	$3,197	$1,206	$697	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$60,073	$60,073	$51,662	$44,519	$51,749	$47,849	$29,183	[s] = [q] + [r].
Market Value of Debt	$60,073	$60,073	$51,662	$44,519	$51,749	$47,849	$29,183	[t] = [s].
MARKET VALUE OF FIRM	$128,964	$124,767	$107,385	$98,589	$96,573	$98,558	$76,406	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	53.19%	51.62%	51.62%	54.55%	46.08%	50.71%	60.85%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.23%	0.23%	0.27%	0.30%	0.34%	0.74%	0.95%	[w] = [i] / [u].
Debt - Market Value Ratio	46.58%	48.15%	48.11%	45.16%	53.59%	48.55%	38.19%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
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[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel AA: Unitil Corp.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equity	$403	$403	$388	$374	$348	$302	$290	[a]
Shares Outstanding (in millions) - Common	15	15	15	15	15	14	14	[b]
Price per Share - Common	$51	$47	$51	$54	$45	$45	$42	[c]
Market Value of Common Equity	$773	$710	$758	$812	$668	$628	$583	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$773	$710	$758	$812	$668	$628	$583	[f]= [d] + [e]
Market to Book Value of Common Equity	1.92	1.76	1.96	2.17	1.92	2.08	2.01	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$133	$133	$126	$134	$145	$126	$128	[j]
Current Liabilities	$123	$123	$147	$165	$146	$177	$146	[k]
Current Portion of Long-Term Debt	$10	$10	$8	$21	$33	$33	$20	[l]
Net Working Capital	$20	$20	($14)	($10)	$31	($18)	$2	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$37	$37	$72	$66	$45	$77	$48	[n]
Adjusted Short-Term Debt	$0	$0	$14	$10	$0	$18	$0	[o] = See Sources and Notes.
Long-Term Debt	$520	$520	$440	$376	$368	$311	$316	[p]
Book Value of Long-Term Debt	$530	$530	$461	$407	$401	$362	$336	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$633	$633	$519	$422	$457	$370	$345	
Carrying Amount	$523	$523	$438	$387	$376	$317	$306	
Adjustment to Book Value of Long-Tern	$110	$110	$81	$35	$81	$54	$40	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$640	$640	$542	$441	$482	$415	$376	[s] = [q] + [r].
Market Value of Debt	$640	$640	$542	$441	$482	$415	$376	[t] = [s].
MARKET VALUE OF FIRM								
	$1,413	$1,350	$1,301	$1,254	$1,150	$1,044	$959	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	54.71%	52.59%	58.29%	64.79%	58.09%	60.18%	60.79%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.01%	0.01%	0.02%	0.02%	0.02%	0.02%	0.02%	[w] = [i] / [u].
Debt - Market Value Ratio	45.27%	47.39%	41.69%	35.20%	41.89%	39.80%	39.19%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel AB: WEC Energy Group

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equi	$10,767	$10,767	$10,344	$9,985	$9,668	$9,126	$8,818	[a]
Shares Outstanding (in millions) - Commo	315	315	315	315	316	316	316	[b]
Price per Share - Common	$96	$91	$89	$78	$62	$60	$59	[c]
Market Value of Common Equity	$30,271	$28,568	$28,187	$24,757	$19,414	$19,054	$18,547	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$30,271	$28,568	$28,187	$24,757	$19,414	$19,054	$18,547	[f]= [d] + [e]
Market to Book Value of Common Equity	2.81	2.65	2.72	2.48	2.01	2.09	2.10	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$30	$30	$30	$30	$30	$30	$30	[h]
Market Value of Preferred Equity	$30	$30	$30	$30	$30	$30	$30	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,356	$2,356	$1,845	$2,008	$1,981	$1,855	$1,896	[j]
Current Liabilities	$3,715	$3,715	$2,848	$2,890	$3,606	$2,055	$2,230	[k]
Current Portion of Long-Term Debt	$787	$787	$694	$370	$958	$158	$152	[l]
Net Working Capital	($572)	($572)	($308)	($512)	($667)	($41)	($181)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,580	$1,580	$827	$1,145	$1,200	$670	$896	[n]
Adjusted Short-Term Debt	$572	$572	$308	$512	$667	$41	$181	[o] = See Sources and Notes.
Long-Term Debt	$12,318	$12,318	$11,195	$10,393	$8,644	$9,173	$9,009	[p]
Book Value of Long-Term Debt	$13,677	$13,677	$12,197	$11,274	$10,269	$9,372	$9,342	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Deb	$14,343	$14,343	$13,036	$10,555	$10,342	$9,818	$9,681	
Carrying Amount	$12,451	$12,451	$11,858	$10,336	$9,562	$9,286	$9,222	
Adjustment to Book Value of Long-Te	$1,893	$1,893	$1,178	$219	$780	$532	$459	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$15,570	$15,570	$13,375	$11,493	$11,049	$9,904	$9,801	[s] = [q] + [r].
Market Value of Debt	$15,570	$15,570	$13,375	$11,493	$11,049	$9,904	$9,801	[t] = [s].
MARKET VALUE OF FIRM	$45,871	$44,169	$41,592	$36,281	$30,494	$28,988	$28,379	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	65.99%	64.68%	67.77%	68.24%	63.67%	65.73%	65.36%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.07%	0.07%	0.07%	0.08%	0.10%	0.10%	0.11%	[w] = [i] / [u].
Debt - Market Value Ratio	33.94%	35.25%	32.16%	31.68%	36.23%	34.17%	34.54%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-3

Market Value of the Electric Sample

Panel AC: Xcel Energy Inc.

($MM)

	DCF Capital Structure	1st Quarter, 2021	1st Quarter, 2020	1st Quarter, 2019	1st Quarter, 2018	1st Quarter, 2017	1st Quarter, 2016	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	03/31/21	03/31/20	03/31/19	03/31/18	03/31/17	03/31/16	
Book Value, Common Shareholder's Equi	$14,700	$14,700	$13,302	$12,329	$11,561	$11,070	$10,672	[a]
Shares Outstanding (in millions) - Comm	538	538	525	515	509	508	508	[b]
Price per Share - Common	$70	$64	$59	$56	$44	$44	$41	[c]
Market Value of Common Equity	$37,781	$34,620	$31,060	$29,051	$22,484	$22,433	$20,839	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$37,781	$34,620	$31,060	$29,051	$22,484	$22,433	$20,839	[f]= [d] + [e]
Market to Book Value of Common Equity	2.57	2.36	2.33	2.36	1.94	2.03	1.95	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,315	$4,315	$2,983	$2,909	$2,782	$2,633	$2,733	[j]
Current Liabilities	$4,877	$4,877	$5,839	$4,424	$4,122	$3,708	$3,189	[k]
Current Portion of Long-Term Debt	$242	$242	$1,245	$170	$457	$755	$657	[l]
Net Working Capital	($320)	($320)	($1,611)	($1,345)	($883)	($319)	$201	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,477	$1,477	$1,765	$1,252	$1,025	$605	$183	[n]
Adjusted Short-Term Debt	$320	$320	$1,611	$1,252	$883	$319	$0	[o] = See Sources and Notes.
Long-Term Debt	$22,757	$22,757	$18,173	$17,727	$14,522	$13,696	$13,148	[p]
Book Value of Long-Term Debt	$23,319	$23,319	$21,029	$19,149	$15,862	$14,771	$13,805	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Deb	$24,412	$24,412	$20,227	$16,755	$16,531	$15,513	$14,095	
Carrying Amount	$20,066	$20,066	$18,109	$16,209	$14,977	$14,450	$13,148	
Adjustment to Book Value of Long-Te	$4,346	$4,346	$2,118	$546	$1,554	$1,063	$947	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$27,665	$27,665	$23,147	$19,695	$17,416	$15,834	$14,752	[s] = [q] + [r].
Market Value of Debt	$27,665	$27,665	$23,147	$19,695	$17,416	$15,834	$14,752	[t] = [s].
MARKET VALUE OF FIRM								
	$65,446	$62,285	$54,207	$48,746	$39,900	$38,267	$35,591	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	57.73%	55.58%	57.30%	59.60%	56.35%	58.62%	58.55%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	42.27%	44.42%	42.70%	40.40%	43.65%	41.38%	41.45%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of April 30, 2021
Capital structure from 1st Quarter, 2021 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 1st Quarter, 2021 balance sheet information and a 15-trading day average closing price ending on 4/30/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 to 2020 10-Ks.

Schedule No. BV-4

Electric Sample

Capital Structure Summary of the Electric Sample

Company	DCF Capital Structure: Common Equity - Value Ratio	DCF Capital Structure: Preferred Equity - Value Ratio	DCF Capital Structure: Debt - Value Ratio	5-Year Average Capital Structure: Common Equity - Value Ratio	5-Year Average Capital Structure: Preferred Equity - Value Ratio	5-Year Average Capital Structure: Debt - Value Ratio
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	0.63	0.00	0.37	0.68	0.00	0.26
Alliant Energy	0.62	0.01	0.37	0.61	0.01	0.37
Amer. Elec. Power	0.51	0.00	0.49	0.55	0.00	0.45
Ameren Corp.	0.60	0.00	0.40	0.61	0.00	0.39
Avista Corp.	0.56	0.00	0.44	0.57	0.00	0.43
Black Hills	0.47	0.00	0.53	0.50	0.00	0.50
CMS Energy Corp.	0.51	0.00	0.49	0.53	0.00	0.47
CenterPoint Energy	0.40	0.07	0.53	0.46	0.04	0.50
Consol. Edison	0.49	0.00	0.51	0.54	0.00	0.46
DTE Energy	0.58	0.00	0.42	0.57	0.00	0.43
Duke Energy	0.50	0.01	0.49	0.50	0.01	0.50
Edison Int'l	0.42	0.06	0.52	0.50	0.05	0.44
Entergy Corp.	0.44	0.01	0.56	0.46	0.01	0.53
Evergy Inc.	0.54	0.00	0.46	0.55	0.00	0.45
Eversource Energy	0.61	0.00	0.39	0.61	0.00	0.39
Exelon Corp.	0.49	0.00	0.51	0.49	0.00	0.51
IDACORP Inc.	0.67	0.00	0.33	0.69	0.00	0.31
MGE Energy	0.80	0.00	0.20	0.81	0.00	0.19
NextEra Energy	0.73	0.00	0.27	0.42	0.00	0.58
NorthWestern Corp.	0.57	0.00	0.43	0.58	0.00	0.42
OGE Energy	0.54	0.00	0.46	0.63	0.00	0.37
Otter Tail Corp.	0.68	0.00	0.32	0.71	0.00	0.29
Pinnacle West Capital	0.53	0.00	0.47	0.60	0.00	0.40
Public Serv. Enterprise	0.61	0.00	0.39	0.62	0.00	0.38
Sempra Energy	0.59	0.02	0.39	0.55	0.02	0.43
Southern Co.	0.53	0.00	0.47	0.51	0.00	0.49
Unitil Corp.	0.55	0.00	0.45	0.59	0.00	0.41
WEC Energy Group	0.66	0.00	0.34	0.66	0.00	0.34
Xcel Energy Inc.	0.58	0.00	0.42	0.57	0.00	0.43
Electric Sample Average	0.57	0.01	0.43	0.57	0.01	0.42

Sources and Notes:
[1], [4]:Workpaper #1 to Schedule No. BV-4.
[2], [5]:Workpaper #2 to Schedule No. BV-4.
[3], [6]:Workpaper #3 to Schedule No. BV-4.
Values in this table may not add up exactly to 1.0 because of rounding.

Schedule No. BV-5

Electric Sample

Estimated Growth Rates of the Electric Sample

	Thomson Reuters IBES Estimate		Value Line			
Company	Long-Term Growth Rate	Number of Estimates	EPS Year 2021 Estimate	EPS Year 2024-2026 Estimate	Annualized Growth Rate	Combined Growth Rate
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	7.0%	1	3.10	4.75	11.3%	9.1%
Alliant Energy	5.7%	3	2.60	3.25	5.7%	5.7%
Amer. Elec. Power	6.2%	4	4.65	6.00	6.6%	6.2%
Ameren Corp.	7.5%	2	3.70	4.75	6.4%	7.1%
Avista Corp.	6.9%	1	2.10	2.75	7.0%	6.9%
Black Hills	4.7%	2	3.85	4.75	5.4%	4.9%
CMS Energy Corp.	7.2%	6	2.85	3.75	7.1%	7.2%
CenterPoint Energy	-5.9%	4	1.40	1.85	7.2%	-3.3%
Consol. Edison	2.9%	3	4.25	5.00	4.1%	3.2%
DTE Energy	6.0%	3	7.15	9.25	6.6%	6.2%
Duke Energy	5.0%	4	5.15	6.25	5.0%	5.0%
Edison Int'l	-0.5%	1	4.10	5.25	6.4%	2.9%
Entergy Corp.	5.5%	3	5.95	7.50	6.0%	5.6%
Evergy Inc.	5.7%	3	3.40	4.25	5.7%	5.7%
Eversource Energy	7.0%	5	3.85	5.00	6.8%	7.0%
Exelon Corp.	5.1%	5	3.00	3.50	3.9%	4.9%
IDACORP Inc.	2.6%	2	4.80	5.75	4.6%	3.3%
MGE Energy	4.7%	1	2.70	3.25	4.7%	4.7%
NextEra Energy	8.6%	7	2.45	3.50	9.3%	8.7%
NorthWestern Corp.	4.6%	3	3.50	4.00	3.4%	4.3%
OGE Energy	3.8%	2	2.10	2.75	7.0%	4.9%
Otter Tail Corp.	9.0%	1	2.45	3.25	7.3%	8.2%
Pinnacle West Capital	3.5%	4	5.05	6.50	6.5%	4.1%
Public Serv. Enterprise	2.6%	4	3.65	4.50	5.4%	3.1%
Sempra Energy	6.1%	2	7.75	10.75	8.5%	6.9%
Southern Co.	6.5%	4	3.25	4.00	5.3%	6.3%
Unitil Corp.	4.8%	1	n/a	n/a	n/a	4.8%
WEC Energy Group	6.1%	4	4.00	5.25	7.0%	6.3%
Xcel Energy Inc.	6.3%	2	2.95	3.75	6.2%	6.3%

Sources and Notes:
[1] - [2]: Thomson Reuters as of April 30, 2021.
[3] - [4]: From Valueline Investment Analyzer as of April 30, 2021.
[5]: ([4] / [3]) ^ (1/4) - 1.
[6]: ([1] x [2] + [5]) / ([2] + 1).
Weighted average growth rate. If information is missing from one source, the weighted average is based solely on the other source.

Schedule No. BV-6

DCF Cost of Equity of the Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	Stock Price	Most Recent Dividend	Quarterly Dividend Yield	Combined Long-Term Growth Rate	Quarterly Growth Rate	DCF Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	$70.17	$0.63	0.92%	9.1%	2.2%	13.1%
Alliant Energy	$55.87	$0.40	0.73%	5.7%	1.4%	8.8%
Amer. Elec. Power	$87.88	$0.74	0.85%	6.2%	1.5%	9.9%
Ameren Corp.	$83.87	$0.55	0.67%	7.1%	1.7%	10.0%
Avista Corp.	$46.86	$0.42	0.92%	6.9%	1.7%	10.8%
Black Hills	$69.50	$0.57	0.82%	4.9%	1.2%	8.4%
CMS Energy Corp.	$63.57	$0.44	0.70%	7.2%	1.7%	10.1%
CenterPoint Energy	$24.01	$0.16	0.66%	-3.3%	-0.8%	-0.7%
Consol. Edison	$77.18	$0.78	1.01%	3.2%	0.8%	7.5%
DTE Energy	$138.64	$1.09	0.79%	6.2%	1.5%	9.6%
Duke Energy	$99.64	$0.97	0.98%	5.0%	1.2%	9.1%
Edison Int'l	$60.04	$0.66	1.11%	2.9%	0.7%	7.6%
Entergy Corp.	$106.36	$0.95	0.91%	5.6%	1.4%	9.4%
Evergy Inc.	$63.07	$0.54	0.86%	5.7%	1.4%	9.3%
Eversource Energy	$87.86	$0.60	0.70%	7.0%	1.7%	10.0%
Exelon Corp.	$45.19	$0.38	0.86%	4.9%	1.2%	8.5%
IDACORP Inc.	$100.73	$0.71	0.71%	3.3%	0.8%	6.2%
MGE Energy	$74.12	$0.37	0.50%	4.7%	1.2%	6.8%
NextEra Energy	$78.59	$0.39	0.50%	8.7%	2.1%	10.8%
NorthWestern Corp.	$68.15	$0.62	0.92%	4.3%	1.1%	8.1%
OGE Energy	$33.15	$0.40	1.23%	4.9%	1.2%	10.0%
Otter Tail Corp.	$47.00	$0.39	0.85%	8.2%	2.0%	11.8%
Pinnacle West Capital	$83.83	$0.83	1.00%	4.1%	1.0%	8.3%
Public Serv. Enterprise	$62.78	$0.51	0.82%	3.1%	0.8%	6.5%
Sempra Energy	$136.72	$1.10	0.82%	6.9%	1.7%	10.4%
Southern Co.	$64.78	$0.64	1.00%	6.3%	1.5%	10.5%
Unitil Corp.	$51.39	$0.38	0.75%	4.8%	1.2%	7.9%
WEC Energy Group	$95.97	$0.68	0.72%	6.3%	1.5%	9.3%
Xcel Energy Inc.	$70.22	$0.46	0.66%	6.3%	1.5%	9.1%

Sources and Notes:
[1]: Workpaper #1 to Schedule No. BV-6.
[2]: Workpaper #2 to Schedule No. BV-6.
[3]: ([2] / [1]) x (1 + [5]).
[4]: Schedule No. BV-5, [6].
[5]: {(1 + [4]) ^ (1/4)} - 1.
[6]: {([3] + [5] + 1) ^ 4} - 1.

Schedule No. BV-6

DCF Cost of Equity of the Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	Stock Price	Most Recent Dividend	Combined Long-Term Growth Rate	Growth Rate: Year 6	Growth Rate: Year 7	Growth Rate: Year 8	Growth Rate: Year 9	Growth Rate: Year 10	GDP Long-Term Growth Rate	DCF Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ALLETE	$70.17	$0.63	9.1%	8.3%	7.4%	6.5%	5.6%	4.8%	3.9%	9.1%
Alliant Energy	$55.87	$0.40	5.7%	5.4%	5.1%	4.8%	4.5%	4.2%	3.9%	7.3%
Amer. Elec. Power	$87.88	$0.74	6.2%	5.8%	5.5%	5.1%	4.7%	4.3%	3.9%	8.0%
Ameren Corp.	$83.87	$0.55	7.1%	6.6%	6.1%	5.5%	5.0%	4.4%	3.9%	7.3%
Avista Corp.	$46.86	$0.42	6.9%	6.4%	5.9%	5.4%	4.9%	4.4%	3.9%	8.5%
Black Hills	$69.50	$0.57	4.9%	4.7%	4.6%	4.4%	4.2%	4.1%	3.9%	7.6%
CMS Energy Corp.	$63.57	$0.44	7.2%	6.6%	6.1%	5.5%	5.0%	4.4%	3.9%	7.4%
CenterPoint Energy	$24.01	$0.16	-3.3%	-2.1%	-0.9%	0.3%	1.5%	2.7%	3.9%	5.6%
Consol. Edison	$77.18	$0.78	3.2%	3.4%	3.5%	3.6%	3.7%	3.8%	3.9%	8.0%
DTE Energy	$138.64	$1.09	6.2%	5.8%	5.4%	5.0%	4.7%	4.3%	3.9%	7.7%
Duke Energy	$99.64	$0.97	5.0%	4.8%	4.6%	4.4%	4.3%	4.1%	3.9%	8.3%
Edison Int'l	$60.04	$0.66	2.9%	3.1%	3.3%	3.4%	3.6%	3.7%	3.9%	8.3%
Entergy Corp.	$106.36	$0.95	5.6%	5.3%	5.0%	4.8%	4.5%	4.2%	3.9%	8.1%
Evergy Inc.	$63.07	$0.54	5.7%	5.4%	5.1%	4.8%	4.5%	4.2%	3.9%	7.9%
Eversource Energy	$87.86	$0.60	7.0%	6.5%	6.0%	5.4%	4.9%	4.4%	3.9%	7.4%
Exelon Corp.	$45.19	$0.38	4.9%	4.7%	4.6%	4.4%	4.2%	4.1%	3.9%	7.7%
IDACORP Inc.	$100.73	$0.71	3.3%	3.4%	3.5%	3.6%	3.7%	3.8%	3.9%	6.7%
MGE Energy	$74.12	$0.37	4.7%	4.6%	4.4%	4.3%	4.2%	4.0%	3.9%	6.1%
NextEra Energy	$78.59	$0.39	8.7%	7.9%	7.1%	6.3%	5.5%	4.7%	3.9%	6.7%
NorthWestern Corp.	$68.15	$0.62	4.3%	4.2%	4.2%	4.1%	4.0%	4.0%	3.9%	7.8%
OGE Energy	$33.15	$0.40	4.9%	4.7%	4.5%	4.4%	4.2%	4.1%	3.9%	9.3%
Otter Tail Corp.	$47.00	$0.39	8.2%	7.4%	6.7%	6.0%	5.3%	4.6%	3.9%	8.4%
Pinnacle West Capital	$83.83	$0.83	4.1%	4.1%	4.0%	4.0%	4.0%	3.9%	3.9%	8.1%
Public Serv. Enterprise	$62.78	$0.51	3.1%	3.2%	3.4%	3.5%	3.6%	3.8%	3.9%	7.1%
Sempra Energy	$136.72	$1.10	6.9%	6.4%	5.9%	5.4%	4.9%	4.4%	3.9%	8.0%
Southern Co.	$64.78	$0.64	6.3%	5.9%	5.5%	5.1%	4.7%	4.3%	3.9%	8.7%
Unitil Corp.	$51.39	$0.38	4.8%	4.7%	4.5%	4.4%	4.2%	4.1%	3.9%	7.2%
WEC Energy Group	$95.97	$0.68	6.3%	5.9%	5.5%	5.1%	4.7%	4.3%	3.9%	7.4%
Xcel Energy Inc.	$70.22	$0.46	6.3%	5.9%	5.5%	5.1%	4.7%	4.3%	3.9%	7.1%

Sources and Notes:
[1]: Workpaper #1 to Schedule No. BV-6.
[2]: Workpaper #2 to Schedule No. BV-6.
[3]: Schedule No. BV-5, [6].
[4]: [3] - {([3] - [9])/ 6}.
[5]: [4] - {([3] - [9])/ 6}.
[6]: [5] - {([3] - [9])/ 6}.
[7]: [6] - {([3] - [9])/ 6}.
[8]: [7] - {([3] - [9])/ 6}.
[9]: BlueChip Economic Indicators, March 2021 This number is assumed to beperpetual.
[10]: Workpaper #3 to Schedule No. BV-6.

Schedule No. BV-7

Overall After-Tax DCF Cost of Capital of the Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	1st Quarter, 2021 S&P Bond Rating	1st Quarter, 2021 Preferred Equity Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	Portland General Electric's Representative Income Tax Rate	Overall Weighted After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ALLETE	BBB	-	13.1%	0.63	-	0.00	3.7%	0.37	27.0%	9.3%
Alliant Energy	A	A	8.8%	0.62	3.4%	0.01	3.4%	0.37	27.0%	6.4%
Amer. Elec. Power	A	-	9.9%	0.51	-	0.00	3.4%	0.49	27.0%	6.2%
Ameren Corp.	BBB	-	10.0%	0.60	-	0.00	3.7%	0.40	27.0%	7.1%
Avista Corp.	BBB	-	10.8%	0.56	-	0.00	3.7%	0.44	27.0%	7.3%
Black Hills	BBB	-	8.4%	0.47	-	0.00	3.7%	0.53	27.0%	5.4%
CMS Energy Corp.	BBB	-	10.1%	0.51	-	0.00	3.7%	0.49	27.0%	6.5%
CenterPoint Energy	BBB	BBB	~~-0.7%~~	0.40	3.7%	0.07	3.7%	0.53	27.0%	~~1.5%~~
Consol. Edison	A	-	7.5%	0.49	-	0.00	3.4%	0.51	27.0%	4.9%
DTE Energy	BBB	-	9.6%	0.58	-	0.00	3.7%	0.42	27.0%	6.7%
Duke Energy	A	A	9.1%	0.50	3.4%	0.01	3.4%	0.49	27.0%	5.8%
Edison Int'l	BBB	BBB	7.6%	0.42	3.7%	0.06	3.7%	0.52	27.0%	4.8%
Entergy Corp.	BBB	BBB	9.4%	0.44	3.7%	0.01	3.7%	0.56	27.0%	5.7%
Evergy Inc.	A	-	9.3%	0.54	-	0.00	3.4%	0.46	27.0%	6.2%
Eversource Energy	A	A	10.0%	0.61	3.4%	0.00	3.4%	0.39	27.0%	7.0%
Exelon Corp.	BBB	-	8.5%	0.49	-	0.00	3.7%	0.51	27.0%	5.6%
IDACORP Inc.	BBB	-	6.2%	0.67	-	0.00	3.7%	0.33	27.0%	5.1%
MGE Energy	AA	-	6.8%	0.80	-	0.00	3.2%	0.20	27.0%	5.9%
NextEra Energy	A	-	10.8%	0.73	-	0.00	3.4%	0.27	27.0%	8.5%
NorthWestern Corp.	BBB	-	8.1%	0.57	-	0.00	3.7%	0.43	27.0%	5.8%
OGE Energy	BBB	-	10.0%	0.54	-	0.00	3.7%	0.46	27.0%	6.7%
Otter Tail Corp.	BBB	-	11.8%	0.68	-	0.00	3.7%	0.32	27.0%	8.9%
Pinnacle West Capital	A	-	8.3%	0.53	-	0.00	3.4%	0.47	27.0%	5.6%
Public Serv. Enterprise	BBB	-	6.5%	0.61	-	0.00	3.7%	0.39	27.0%	5.0%
Sempra Energy	BBB	BBB	10.4%	0.59	3.7%	0.02	3.7%	0.39	27.0%	7.3%
Southern Co.	A	A	10.5%	0.53	3.4%	0.00	3.4%	0.47	27.0%	6.7%
Unitil Corp.	BBB	BBB	7.9%	0.55	3.7%	0.00	3.7%	0.45	27.0%	5.6%
WEC Energy Group	A	A	9.3%	0.66	3.4%	0.00	3.4%	0.34	27.0%	7.0%
Xcel Energy Inc.	A	-	9.1%	0.58	-	0.00	3.4%	0.42	27.0%	6.3%
Simple Electric Sample Average			9.2%	0.57	3.5%	0.00	3.6%	0.42	27.0%	6.4%

Sources and Notes:
[1]: Bloomberg as of March 31, 2021.
[2]: Preferred ratings were assumed equal to debt rating
[3]: Schedule No. BV-6; Panel A, [6].
[4]: Schedule No. BV-4, [1].
[5]: Workpaper #2 to Schedule No. BV-11, Panel C.
[6]: Schedule No. BV-4, [2].
[7]: Workpaper #2 to Schedule No. BV-11, Panel B.
[8]: Schedule No. BV-4, [3].
[9]: Provided by Portland General Electric.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

Schedule No. BV-7

Overall After-Tax DCF Cost of Capital of the Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	1st Quarter, 2021 S&P Bond Rating	1st Quarter, 2021 Preferred Equity Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	Portland General Electric's Representative Income Tax Rate	Overall Weighted After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ALLETE	BBB	-	9.1%	0.63	-	0.00	3.7%	0.37	27.0%	6.8%
Alliant Energy	A	A	7.3%	0.62	3.4%	0.01	3.4%	0.37	27.0%	5.5%
Amer. Elec. Power	A	-	8.0%	0.51	-	0.00	3.4%	0.49	27.0%	5.3%
Ameren Corp.	BBB	-	7.3%	0.60	-	0.00	3.7%	0.40	27.0%	5.5%
Avista Corp.	BBB	-	8.5%	0.56	-	0.00	3.7%	0.44	27.0%	5.9%
Black Hills	BBB	-	7.6%	0.47	-	0.00	3.7%	0.53	27.0%	5.0%
CMS Energy Corp.	BBB	-	7.4%	0.51	-	0.00	3.7%	0.49	27.0%	5.1%
CenterPoint Energy	BBB	BBB	5.6%	0.40	3.7%	0.07	3.7%	0.53	27.0%	3.9%
Consol. Edison	A	-	8.0%	0.49	-	0.00	3.4%	0.51	27.0%	5.1%
DTE Energy	BBB	-	7.7%	0.58	-	0.00	3.7%	0.42	27.0%	5.6%
Duke Energy	A	A	8.3%	0.50	3.4%	0.01	3.4%	0.49	27.0%	5.4%
Edison Int'l	BBB	BBB	8.3%	0.42	3.7%	0.06	3.7%	0.52	27.0%	5.1%
Entergy Corp.	BBB	BBB	8.1%	0.44	3.7%	0.01	3.7%	0.56	27.0%	5.1%
Evergy Inc.	A	-	7.9%	0.54	-	0.00	3.4%	0.46	27.0%	5.4%
Eversource Energy	A	A	7.4%	0.61	3.4%	0.00	3.4%	0.39	27.0%	5.5%
Exelon Corp.	BBB	-	7.7%	0.49	-	0.00	3.7%	0.51	27.0%	5.2%
IDACORP Inc.	BBB	-	6.7%	0.67	-	0.00	3.7%	0.33	27.0%	5.4%
MGE Energy	AA	-	6.1%	0.80	-	0.00	3.2%	0.20	27.0%	5.4%
NextEra Energy	A	-	6.7%	0.73	-	0.00	3.4%	0.27	27.0%	5.5%
NorthWestern Corp.	BBB	-	7.8%	0.57	-	0.00	3.7%	0.43	27.0%	5.6%
OGE Energy	BBB	-	9.3%	0.54	-	0.00	3.7%	0.46	27.0%	6.3%
Otter Tail Corp.	BBB	-	8.4%	0.68	-	0.00	3.7%	0.32	27.0%	6.6%
Pinnacle West Capital	A	-	8.1%	0.53	-	0.00	3.4%	0.47	27.0%	5.5%
Public Serv. Enterprise	BBB	-	7.1%	0.61	-	0.00	3.7%	0.39	27.0%	5.4%
Sempra Energy	BBB	BBB	8.0%	0.59	3.7%	0.02	3.7%	0.39	27.0%	5.8%
Southern Co.	A	A	8.7%	0.53	3.4%	0.00	3.4%	0.47	27.0%	5.8%
Unitil Corp.	BBB	BBB	7.2%	0.55	3.7%	0.00	3.7%	0.45	27.0%	5.2%
WEC Energy Group	A	A	7.4%	0.66	3.4%	0.00	3.4%	0.34	27.0%	5.7%
Xcel Energy Inc.	A	-	7.1%	0.58	-	0.00	3.4%	0.42	27.0%	5.1%
Multi-Stage Electric Sample Average			7.7%	0.57	3.5%	0.01	3.6%	0.43	27.0%	5.5%

Sources and Notes:

[1]: Bloomberg as of March 31, 2021.
[2]: Preferred ratings were assumed equal to debt rating
[3]: Schedule No. BV-6, Panel B, [10].
[4]: Schedule No. BV-4, [1].
[5]: Workpaper #2 to Schedule No. BV-11, Panel C.
[6]: Schedule No. BV-4, [2].
[7]: Workpaper #2 to Schedule No. BV-11, Panel B.
[8]: Schedule No. BV-4, [3].
[9]: Provided by Portland General Electric.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

Schedule No. BV-8

DCF Cost of Equity at Portland General Electric's Proposed Capital Structure

Electric Sample

	Overall After - Tax Cost of Capital	Portland General Electric's Representative Regulatory % Debt	Representative Cost of BBB Rated Utility Debt	Portland General Electric's Representative Income Tax Rate	Portland General Electric's Representative Regulatory % Equity	Estimated Return on Equity
	[1]	[2]	[3]	[4]	[5]	[6]
Electric Sample						
Simple DCF Quarterly	6.4%	50.0%	3.7%	27.0%	50.0%	10.1%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Rate	5.5%	50.0%	3.7%	27.0%	50.0%	8.2%

Sources and Notes:
[1]: Schedule No. BV-7; Panels A-B, [10].
[2]: Provided by Portland General Electric.
[3]: Based on a BBB rating. Yield from Bloomberg as of April 30, 2021.
[4]: Provided by Portland General Electric.
[5]: Provided by Portland General Electric.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

Schedule No. BV-9 Risk-Free Rates

BCEI Forecast of 10 year U.S. Treasury Yield	**[a]**	**2.30%**
Long-run Average of 20 year U.S. Treasury Yield	[b]	5.01%
Long-run Average of 10 year U.S. Treasury Yield	[c]	4.53%
Maturity Premium	**[d] = [b] - [c]**	**0.50%**
Base Projection of 20 year U.S. Treasury Yield	**[e] = [a] + [d]**	**2.80%**

Sources and Notes:
[a]: Blue Chip Economic Indicators, May 2021 (for 2022) and March 2021 (for 2023 and 20
Average Projection for 2022, 2023 and 2024 Yield.
[b], [c]: Bloomberg as of 3/31/2021, see Workpaper #1 to Schedule No. BV-9.

Schedule No. BV-10

Risk Positioning Cost of Equity of the Electric Sample (Using Value Line Betas)

Panel A: Scenario 1 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%

Company	Long-Term Risk-Free Rate	Value Line Betas	Long-Term Market Risk Premium	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
ALLETE	2.80%	0.90	7.25%	9.3%	9.5%
Alliant Energy	2.80%	0.85	7.25%	9.0%	9.2%
Amer. Elec. Power	2.80%	0.75	7.25%	8.2%	8.6%
Ameren Corp.	2.80%	0.80	7.25%	8.6%	8.9%
Avista Corp.	2.80%	0.95	7.25%	9.7%	9.8%
Black Hills	2.80%	1.00	7.25%	10.1%	10.1%
CMS Energy Corp.	2.80%	0.75	7.25%	8.2%	8.6%
CenterPoint Energy	2.80%	1.15	7.25%	11.1%	10.9%
Consol. Edison	2.80%	0.75	7.25%	8.2%	8.6%
DTE Energy	2.80%	0.95	7.25%	9.7%	9.8%
Duke Energy	2.80%	0.85	7.25%	9.0%	9.2%
Edison Int'l	2.80%	0.95	7.25%	9.7%	9.8%
Entergy Corp.	2.80%	0.95	7.25%	9.7%	9.8%
Evergy Inc.	2.80%	0.95	7.25%	9.7%	9.8%
Eversource Energy	2.80%	0.90	7.25%	9.3%	9.5%
Exelon Corp.	2.80%	0.95	7.25%	9.7%	9.8%
IDACORP Inc.	2.80%	0.80	7.25%	8.6%	8.9%
MGE Energy	2.80%	0.70	7.25%	7.9%	8.3%
NextEra Energy	2.80%	0.90	7.25%	9.3%	9.5%
NorthWestern Corp.	2.80%	0.95	7.25%	9.7%	9.8%
OGE Energy	2.80%	1.05	7.25%	10.4%	10.3%
Otter Tail Corp.	2.80%	0.85	7.25%	9.0%	9.2%
Pinnacle West Capital	2.80%	0.90	7.25%	9.3%	9.5%
Public Serv. Enterprise	2.80%	0.90	7.25%	9.3%	9.5%
Sempra Energy	2.80%	0.95	7.25%	9.7%	9.8%
Southern Co.	2.80%	0.95	7.25%	9.7%	9.8%
Unitil Corp.	2.80%	0.85	7.25%	9.0%	9.2%
WEC Energy Group	2.80%	0.80	7.25%	8.6%	8.9%
Xcel Energy Inc.	2.80%	0.80	7.25%	8.6%	8.9%

Sources and Notes:
[1], [3]: Villadsen Direct Testimony.
[2]: From Valueline Investment Analyzer as of April 30, 2021.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-10

Risk Positioning Cost of Equity of the Electric Sample (Using Value Line Betas)

Panel B: Scenario 2 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%

Company	Long-Term Risk-Free Rate	Value Line Betas	Long-Term Market Risk Premium	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
ALLETE	2.80%	0.90	8.00%	10.0%	10.2%
Alliant Energy	2.80%	0.85	8.00%	9.6%	9.8%
Amer. Elec. Power	2.80%	0.75	8.00%	8.8%	9.2%
Ameren Corp.	2.80%	0.80	8.00%	9.2%	9.5%
Avista Corp.	2.80%	0.95	8.00%	10.4%	10.5%
Black Hills	2.80%	1.00	8.00%	10.8%	10.8%
CMS Energy Corp.	2.80%	0.75	8.00%	8.8%	9.2%
CenterPoint Energy	2.80%	1.15	8.00%	12.0%	11.8%
Consol. Edison	2.80%	0.75	8.00%	8.8%	9.2%
DTE Energy	2.80%	0.95	8.00%	10.4%	10.5%
Duke Energy	2.80%	0.85	8.00%	9.6%	9.8%
Edison Int'l	2.80%	0.95	8.00%	10.4%	10.5%
Entergy Corp.	2.80%	0.95	8.00%	10.4%	10.5%
Evergy Inc.	2.80%	0.95	8.00%	10.4%	10.5%
Eversource Energy	2.80%	0.90	8.00%	10.0%	10.2%
Exelon Corp.	2.80%	0.95	8.00%	10.4%	10.5%
IDACORP Inc.	2.80%	0.80	8.00%	9.2%	9.5%
MGE Energy	2.80%	0.70	8.00%	8.4%	8.9%
NextEra Energy	2.80%	0.90	8.00%	10.0%	10.2%
NorthWestern Corp.	2.80%	0.95	8.00%	10.4%	10.5%
OGE Energy	2.80%	1.05	8.00%	11.2%	11.1%
Otter Tail Corp.	2.80%	0.85	8.00%	9.6%	9.8%
Pinnacle West Capital	2.80%	0.90	8.00%	10.0%	10.2%
Public Serv. Enterprise	2.80%	0.90	8.00%	10.0%	10.2%
Sempra Energy	2.80%	0.95	8.00%	10.4%	10.5%
Southern Co.	2.80%	0.95	8.00%	10.4%	10.5%
Unitil Corp.	2.80%	0.85	8.00%	9.6%	9.8%
WEC Energy Group	2.80%	0.80	8.00%	9.2%	9.5%
Xcel Energy Inc.	2.80%	0.80	8.00%	9.2%	9.5%

Sources and Notes:
[1], [3]: Villadsen Direct Testimony.
[2]: From Valueline Investment Analyzer as of April 30, 2021.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-11

Overall After-Tax Risk Positioning Cost of Capital of the Electric Sample (Using Value Line Betas)

Panel A: CAPM Cost of Equity Scenario 1 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%

Company	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity	5-Year Average Common Equity to Market Value Ratio	Weighted - Average Cost of Preferred Equity	5-Year Average Preferred Equity to Market Value Ratio	Weighted-Average Cost of Debt	5-Year Average Debt to Market Value Ratio	Electric's Representative Income Tax Rate	Overall After-Tax Cost of Capital (CAPM)	Overall After-Tax Cost of Capital (ECAPM 1.5%)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ALLETE	9.3%	9.5%	0.68	-	0.00	3.7%	0.26	27.0%	7.0%	7.1%
Alliant Energy	9.0%	9.2%	0.61	3.4%	0.01	3.4%	0.37	27.0%	6.5%	6.6%
Amer. Elec. Power	8.2%	8.6%	0.55	-	0.00	3.4%	0.45	27.0%	5.7%	5.9%
Ameren Corp.	8.6%	8.9%	0.61	-	0.00	3.7%	0.39	27.0%	6.3%	6.5%
Avista Corp.	9.7%	9.8%	0.57	-	0.00	3.7%	0.43	27.0%	6.7%	6.8%
Black Hills	10.1%	10.1%	0.50	-	0.00	3.7%	0.50	27.0%	6.4%	6.4%
CMS Energy Corp.	8.2%	8.6%	0.53	-	0.00	3.7%	0.47	27.0%	5.7%	5.8%
CenterPoint Energy	11.1%	10.9%	0.46	3.7%	0.04	3.5%	0.50	27.0%	6.6%	6.5%
Consol. Edison	8.2%	8.6%	0.54	-	0.00	3.4%	0.46	27.0%	5.6%	5.8%
DTE Energy	9.7%	9.8%	0.57	-	0.00	3.7%	0.43	27.0%	6.7%	6.7%
Duke Energy	9.0%	9.2%	0.50	3.4%	0.01	3.4%	0.50	27.0%	5.7%	5.8%
Edison Int'l	9.7%	9.8%	0.50	3.7%	0.05	3.7%	0.44	27.0%	6.3%	6.3%
Entergy Corp.	9.7%	9.8%	0.46	3.7%	0.01	3.7%	0.53	27.0%	5.9%	6.0%
Evergy Inc.	9.7%	9.8%	0.55	-	0.00	3.4%	0.45	27.0%	6.4%	6.5%
Eversource Energy	9.3%	9.5%	0.61	3.4%	0.00	3.4%	0.39	27.0%	6.6%	6.7%
Exelon Corp.	9.7%	9.8%	0.49	-	0.00	3.7%	0.51	27.0%	6.2%	6.2%
IDACORP Inc.	8.6%	8.9%	0.69	-	0.00	3.7%	0.31	27.0%	6.8%	7.0%
MGE Energy	7.9%	8.3%	0.81	-	0.00	3.2%	0.19	27.0%	6.8%	7.2%
NextEra Energy	9.3%	9.5%	0.42	-	0.00	3.4%	0.58	27.0%	5.3%	5.4%
NorthWestern Corp.	9.7%	9.8%	0.58	-	0.00	3.7%	0.42	27.0%	6.8%	6.8%
OGE Energy	10.4%	10.3%	0.63	-	0.00	3.6%	0.37	27.0%	7.6%	7.5%
Otter Tail Corp.	9.0%	9.2%	0.71	-	0.00	3.7%	0.29	27.0%	7.2%	7.3%
Pinnacle West Capital	9.3%	9.5%	0.60	-	0.00	3.4%	0.40	27.0%	6.6%	6.7%
Public Serv. Enterprise	9.3%	9.5%	0.62	-	0.00	3.7%	0.38	27.0%	6.8%	6.9%
Sempra Energy	9.7%	9.8%	0.55	3.7%	0.02	3.7%	0.43	27.0%	6.5%	6.6%
Southern Co.	9.7%	9.8%	0.51	3.4%	0.00	3.4%	0.49	27.0%	6.1%	6.2%
Unitil Corp.	9.0%	9.2%	0.59	3.7%	0.00	3.7%	0.41	27.0%	6.4%	6.5%
WEC Energy Group	8.6%	8.9%	0.66	3.4%	0.00	3.4%	0.34	27.0%	6.5%	6.7%
Xcel Energy Inc.	8.6%	8.9%	0.57	-	0.00	3.4%	0.43	27.0%	6.0%	6.2%
Electric Sample Average	9.3%	9.4%	0.57	3.5%	0.01	3.6%	0.42	27.0%	6.4%	6.5%

Sources and Notes:
[1]: Schedule No. BV-10; Panel A, [4].
[2]: Schedule No. BV-10; Panel A, [5].
[3]: Schedule No. BV-4, [4].
[4]: Workpaper #2 to Schedule No. BV-11, Panel C.
[5]: Schedule No. BV-4, [5].
[6]: Workpaper #2 to Schedule No. BV-11, Panel B.
[7]: Schedule No. BV-4, [6].
[8]: Provided by Portland General Electric.
[9] = [1] x [3] + [4] x [5] + [6] x [7] x (1 - [8])
[10] = [2] x [3] + [4] x [5] + [6] x [7] x (1 - [8])

Schedule No. BV-11

Overall After-Tax Risk Positioning Cost of Capital of the Electric Sample (Using Value Line Betas)

Panel B: CAPM Cost of Equity Scenario 2 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%

Company	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity	5-Year Average Common Equity to Market Value Ratio	Weighted - Average Cost of Preferred Equity	5-Year Average Preferred Equity to Market Value Ratio	Weighted- Average Cost of Debt	5-Year Average Debt to Market Value Ratio	Electric's Representative Income Tax Rate	Overall After-Tax Cost of Capital (CAPM)	Overall After-Tax Cost of Capital (ECAPM 1.5%)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	capmlt	ecapmlt2	capm_equity_ratio	average	capm_pref_ratio	average	capm_debt_ratio		CAPM	ECAPM2
ALLETE	10.0%	10.2%	0.68	-	0.00	3.7%	0.26	27.0%	7.5%	7.6%
Alliant Energy	9.6%	9.8%	0.61	3.4%	0.01	3.4%	0.37	27.0%	6.9%	7.0%
Amer. Elec. Power	8.8%	9.2%	0.55	-	0.00	3.4%	0.45	27.0%	6.0%	6.2%
Ameren Corp.	9.2%	9.5%	0.61	-	0.00	3.7%	0.39	27.0%	6.7%	6.9%
Avista Corp.	10.4%	10.5%	0.57	-	0.00	3.7%	0.43	27.0%	7.1%	7.2%
Black Hills	10.8%	10.8%	0.50	-	0.00	3.7%	0.50	27.0%	6.8%	6.8%
CMS Energy Corp.	8.8%	9.2%	0.53	-	0.00	3.7%	0.47	27.0%	5.9%	6.1%
CenterPoint Energy	12.0%	11.8%	0.46	3.7%	0.04	3.5%	0.50	27.0%	7.0%	6.9%
Consol. Edison	8.8%	9.2%	0.54	-	0.00	3.4%	0.46	27.0%	5.9%	6.1%
DTE Energy	10.4%	10.5%	0.57	-	0.00	3.7%	0.43	27.0%	7.1%	7.1%
Duke Energy	9.6%	9.8%	0.50	3.4%	0.01	3.4%	0.50	27.0%	6.0%	6.1%
Edison Int'l	10.4%	10.5%	0.50	3.7%	0.05	3.7%	0.44	27.0%	6.6%	6.7%
Entergy Corp.	10.4%	10.5%	0.46	3.7%	0.01	3.7%	0.53	27.0%	6.3%	6.3%
Evergy Inc.	10.4%	10.5%	0.55	-	0.00	3.4%	0.45	27.0%	6.8%	6.9%
Eversource Energy	10.0%	10.2%	0.61	3.4%	0.00	3.4%	0.39	27.0%	7.0%	7.1%
Exelon Corp.	10.4%	10.5%	0.49	-	0.00	3.7%	0.51	27.0%	6.5%	6.5%
IDACORP Inc.	9.2%	9.5%	0.69	-	0.00	3.7%	0.31	27.0%	7.2%	7.4%
MGE Energy	8.4%	8.9%	0.81	-	0.00	3.2%	0.19	27.0%	7.2%	7.6%
NextEra Energy	10.0%	10.2%	0.42	-	0.00	3.4%	0.58	27.0%	5.6%	5.7%
NorthWestern Corp.	10.4%	10.5%	0.58	-	0.00	3.7%	0.42	27.0%	7.2%	7.2%
OGE Energy	11.2%	11.1%	0.63	-	0.00	3.6%	0.37	27.0%	8.1%	8.0%
Otter Tail Corp.	9.6%	9.8%	0.71	-	0.00	3.7%	0.29	27.0%	7.6%	7.8%
Pinnacle West Capital	10.0%	10.2%	0.60	-	0.00	3.4%	0.40	27.0%	7.0%	7.1%
Public Serv. Enterprise	10.0%	10.2%	0.62	-	0.00	3.7%	0.38	27.0%	7.2%	7.3%
Sempra Energy	10.4%	10.5%	0.55	3.7%	0.02	3.7%	0.43	27.0%	6.9%	7.0%
Southern Co.	10.4%	10.5%	0.51	3.4%	0.00	3.4%	0.49	27.0%	6.5%	6.5%
Unitil Corp.	9.6%	9.8%	0.59	3.7%	0.00	3.7%	0.41	27.0%	6.8%	6.9%
WEC Energy Group	9.2%	9.5%	0.66	3.4%	0.00	3.4%	0.34	27.0%	6.9%	7.1%
Xcel Energy Inc.	9.2%	9.5%	0.57	-	0.00	3.4%	0.43	27.0%	6.3%	6.5%
#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	27.0%	n/a	n/a
Electric Sample Average	9.9%	10.1%	0.57	3.5%	0.01	3.6%	0.42	27.0%	6.8%	6.9%

Sources and Notes:
[1]: Schedule No. BV-10; Panel B, [4].
[2]: Schedule No. BV-10; Panel B, [5].
[3]: Schedule No. BV-4, [4].
[4]: Workpaper #2 to Schedule No. BV-11, Panel C.
[5]: Schedule No. BV-4, [5].
[6]: Workpaper #2 to Schedule No. BV-11, Panel B.
[7]: Schedule No. BV-4, [6].
[8]: Provided by Portland General Electric.
[9] = [1] x [3] + [4] x [5] + [6] x [7] x (1 - [8])
[10] = [2] x [3] + [4] x [5] + [6] x [7] x (1 - [8])

Schedule No. BV-12

Risk Positioning Cost of Equity at Portland General Electric's Proposed Capital Structure

Electric Sample

Using Value Line Betas

	Overall After-Tax Cost of Capital (Scenario 1)	Overall After-Tax Cost of Capital (Scenario 2)	Portland General Electric's Representative Regulatory % Debt	Representative Cost of BBB-Rated Utility Debt	Portland General Electric's Representative Income Tax Rate	Portland General Electric's Representative Regulatory % Equity	Estimated Return on Equity (Scenario 1)	Estimated Return on Equity (Scenario 2)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Electric Sample								
CAPM using Value Line Betas	6.4%	6.8%	50.0%	3.7%	27.0%	50.0%	10.1%	10.8%
ECAPM (1.50%) using Value Line Betas	6.5%	6.9%	50.0%	3.7%	27.0%	50.0%	10.3%	11.0%

Sources and Notes:
[1]: Schedule No. BV-11; Panel A, [9] - [10].
[2]: Schedule No. BV-11; Panel B, [9] - [10].
[3]: Provided by Portland General Electric.
[4]: Based on a BBB rating. Yield from Bloomberg as of April 30, 2021.
[5]: Provided by Portland General Electric.
[6]: Provided by Portland General Electric.
[7]: {[1] - ([3] x [4] x (1 - [5])}/ [6]
[8]: {[2] - ([3] x [4] x (1 - [5]))}/ [6]

Scenario 1: Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%.
Scenario 2: Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%.

Schedule No. BV-13

Hamada Adjustment to Obtain Unlevered Asset Beta

Company		Value Line Betas	Debt Beta	5-Year Average Common Equity to Market Value Ratio	5-Year Average Preferred Equity to Market Value Ratio	5-Year Average Debt to Market Value Ratio	Portland General Electric's Representative Income Tax Rate	Asset Beta: Without Taxes	Asset Beta: With Taxes
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
ALLETE	*	0.90	0.10	0.68	0.00	0.26	27.0%	0.64	0.73
Alliant Energy	*	0.85	0.05	0.61	0.01	0.37	27.0%	0.54	0.60
Amer. Elec. Power	*	0.75	0.06	0.55	0.00	0.45	27.0%	0.44	0.49
Ameren Corp.	*	0.80	0.10	0.61	0.00	0.39	27.0%	0.53	0.58
Avista Corp.	*	0.95	0.10	0.57	0.00	0.43	27.0%	0.59	0.65
Black Hills	*	1.00	0.10	0.50	0.00	0.50	27.0%	0.55	0.62
CMS Energy Corp.	*	0.75	0.10	0.53	0.00	0.47	27.0%	0.44	0.49
CenterPoint Energy	*	1.15	0.08	0.46	0.04	0.50	27.0%	0.57	0.65
Consol. Edison	*	0.75	0.05	0.54	0.00	0.46	27.0%	0.43	0.48
DTE Energy	*	0.95	0.10	0.57	0.00	0.43	27.0%	0.58	0.65
Duke Energy	*	0.85	0.05	0.50	0.01	0.50	27.0%	0.45	0.51
Edison Int'l	*	0.95	0.10	0.50	0.05	0.44	27.0%	0.53	0.58
Entergy Corp.	*	0.95	0.10	0.46	0.01	0.53	27.0%	0.49	0.56
Evergy Inc.	*	0.95	0.05	0.55	0.00	0.45	27.0%	0.55	0.62
Eversource Energy	*	0.90	0.05	0.61	0.00	0.39	27.0%	0.56	0.63
Exelon Corp.	*	0.95	0.10	0.49	0.00	0.51	27.0%	0.52	0.59
IDACORP Inc.	*	0.80	0.10	0.69	0.00	0.31	27.0%	0.58	0.62
MGE Energy	*	0.70	0.05	0.81	0.00	0.19	27.0%	0.57	0.60
NextEra Energy	*	0.90	0.05	0.42	0.00	0.58	27.0%	0.41	0.47
NorthWestern Corp.	*	0.95	0.10	0.58	0.00	0.42	27.0%	0.60	0.66
OGE Energy	*	1.05	0.08	0.63	0.00	0.37	27.0%	0.69	0.76
Otter Tail Corp.	*	0.85	0.10	0.71	0.00	0.29	27.0%	0.63	0.68
Pinnacle West Capital	*	0.90	0.05	0.60	0.00	0.40	27.0%	0.56	0.62
Public Serv. Enterprise	*	0.90	0.10	0.62	0.00	0.38	27.0%	0.59	0.65
Sempra Energy	*	0.95	0.10	0.55	0.02	0.43	27.0%	0.56	0.62
Southern Co.	*	0.95	0.05	0.51	0.00	0.49	27.0%	0.51	0.58
Unitil Corp.	*	0.85	0.10	0.59	0.00	0.41	27.0%	0.54	0.60
WEC Energy Group	*	0.80	0.05	0.66	0.00	0.34	27.0%	0.55	0.60
Xcel Energy Inc.	*	0.80	0.05	0.57	0.00	0.43	27.0%	0.48	0.54
Electric Sample Average		0.89	0.08	0.57	0.01	0.42	0.27	0.54	0.60

Sources and Notes:
[1]: Workpaper # 1 to Schedule No. BV-10, [1].
[2]: Workpaper #1 to Schedule No. BV-13, [7].
[3]: Schedule No. BV-4, [4].
[4]: Schedule No. BV-4, [5].
[5]: Schedule No. BV-4, [6].
[6]: Portland General Electric's Representative Tax Rate.
[7]: [1]*[3] + [2]*([4] + [5]).
[8]: {[1]*[3] + [2]*([4]+[5]*(1-[6]))} / {[3] + [4] + [5]*(1 -[6])}.

Schedule No. BV-14

Electric Sample Average Asset Beta Relevered at Portland General Electric's Proposed Capital Structure

	Asset Beta	Assumed Debt Beta	Portland General Electric's Representative Regulatory % Debt	Portland General Electric's Representative Income Tax Rate	Portland General Electric's Representative Regulatory % Equity	Estimated Equity Beta
	[1]	[2]	[3]	[4]	[5]	[6]
Electric Sample						
Asset Beta Without Taxes	0.54	0.10	50.0%	27.0%	50.0%	0.98
Asset Beta With Taxes	0.60	0.10	50.0%	27.0%	50.0%	0.97

Sources and Notes:
[1]: Schedule No. BV-13, [7] - [8].
[2]: Villadsen Testimony.
[3]: Provided by Portland General Electric.
[4]: Portland General Electric's Representative Tax Rate.
[5]: Provided by Portland General Electric.
[6]: [1] + [3]/[5]*([1] - [2]) without taxes, [1] + [3]*(1 - [4])/[5]*([1] - [2]) with taxes.

Schedule No. BV-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel A: Scenario 1 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%

Company	Long-Term Risk-Free Rate	Hamada Adjusted Equity Betas	Long-Term Market Risk	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Electric Sample					
Asset Beta Without Taxes	2.80%	0.98	7.25%	9.9%	9.9%
Asset Beta With Taxes	2.80%	0.97	7.25%	9.8%	9.9%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Schedule No. BV-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel B: Scenario 2 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%

Company	Long-Term Risk-Free Rate	Hamada Adjusted Equity Betas	Long-Term Market Risk	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Electric Sample					
Asset Beta Without Taxes	2.80%	0.98	8.00%	10.7%	10.7%
Asset Beta With Taxes	2.80%	0.97	8.00%	10.5%	10.6%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Schedule No. BV-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-16
Risk Premiums Determined by Relationship Between Authorized ROEs[1] and Long-term Treasury Bond Rates During the Period 1990 - 2021 Includes Utility Yield Spread Adjustment Electric Utilities

Risk Premium = A_0 + (A_1 x Treasury Bond Rate)

R Squared	0.859
Estimate of Intercept (A_0)	8.53%
Estimate of Slope (A_1)	-0.552

Predicted Risk Premium		Exp. Treasury Bond Rate		Est. Cost of Equity for All Electric Utilities
7.03%	+	2.73%	=	9.8%

Sources and Notes:

[1]: Authorized ROE Data from S&P Market Intelligence as of 02/28/2021.

[2]: March 2021 Blue Chip consensus forecast for 2022-24 10 year T-bill yield + maturity premium between 10 year and 20 year U.S. Government bonds + utility yield spread adjustment.

See Regression Results for derivation of regression coefficients A_0 and A_1

Regression Results

Electric Utilities

	Slope	Intercept
Coefficient	-0.552	0.085
Standard Error	0.020	0.001
R Squared	0.859	-

Note: Estimated by regressing Risk Premium on 20 year Treasury Bond Yield.

Quarterly Risk Premiums for Electric Utilities

1990 - 2021

Quarter	Average Authorized Return on Equity [1]	20 year Treasury Bond Yield [2]	Risk Premium [3] = [1] - [2]
1990 Q1	12.62%	8.44%	4.19%
1990 Q2	12.85%	8.66%	4.19%
1990 Q3	12.54%	8.75%	3.79%
1990 Q4	12.68%	8.47%	4.21%
1991 Q1	12.66%	8.11%	4.55%
1991 Q2	12.67%	8.23%	4.44%
1991 Q3	12.49%	8.07%	4.43%
1991 Q4	12.42%	7.60%	4.83%
1992 Q1	12.38%	7.55%	4.83%
1992 Q2	11.83%	7.64%	4.18%
1992 Q3	12.03%	7.04%	4.99%
1992 Q4	12.14%	7.14%	5.00%
1993 Q1	11.84%	6.68%	5.15%
1993 Q2	11.64%	6.43%	5.21%
1993 Q3	11.15%	5.97%	5.18%
1993 Q4	11.04%	6.28%	4.76%
1994 Q1	11.07%	6.65%	4.41%
1994 Q2	11.13%	7.48%	3.65%
1994 Q3	12.75%	7.72%	5.03%
1994 Q4	11.24%	8.09%	3.15%
1995 Q1	11.96%	7.76%	4.20%
1995 Q2	11.32%	7.02%	4.30%
1995 Q3	11.37%	6.77%	4.60%
1995 Q4	11.58%	6.30%	5.28%
1996 Q1	11.46%	6.38%	5.08%
1996 Q2	11.46%	7.10%	4.36%
1996 Q3	10.70%	7.09%	3.61%
1996 Q4	11.56%	6.71%	4.85%
1997 Q1	11.08%	6.91%	4.17%
1997 Q2	11.62%	7.02%	4.60%
1997 Q3	12.00%	6.59%	5.41%
1997 Q4	11.06%	6.22%	4.84%
1998 Q1	11.31%	5.95%	5.36%
1998 Q2	12.20%	5.94%	6.26%
1998 Q3	11.65%	5.61%	6.04%
1998 Q4	12.30%	5.38%	6.92%
1999 Q1	10.40%	5.66%	4.74%
1999 Q2	10.94%	6.09%	4.85%
1999 Q3	10.75%	6.40%	4.35%
1999 Q4	11.10%	6.61%	4.49%

Quarterly Risk Premiums for Electric Utilities

1990 - 2021

Quarter	Average Authorized Return on Equity [1]	20 year Treasury Bond Yield [2]	Risk Premium [3] = [1] - [2]
2000 Q1	11.21%	6.59%	4.62%
2000 Q2	11.00%	6.34%	4.66%
2000 Q3	11.68%	6.10%	5.58%
2000 Q4	12.50%	5.89%	6.61%
2001 Q1	11.38%	5.59%	5.79%
2001 Q2	10.88%	5.84%	5.04%
2001 Q3	10.76%	5.62%	5.14%
2001 Q4	11.57%	5.48%	6.09%
2002 Q1	10.05%	5.74%	4.31%
2002 Q2	11.41%	5.77%	5.64%
2002 Q3	11.25%	5.19%	6.06%
2002 Q4	11.57%	5.02%	6.55%
2003 Q1	11.43%	4.90%	6.52%
2003 Q2	11.16%	4.59%	6.57%
2003 Q3	9.88%	5.17%	4.70%
2003 Q4	11.09%	5.16%	5.93%
2004 Q1	11.00%	4.89%	6.11%
2004 Q2	10.64%	5.36%	5.28%
2004 Q3	10.75%	5.07%	5.68%
2004 Q4	10.91%	4.87%	6.04%
2005 Q1	10.56%	4.76%	5.80%
2005 Q2	10.13%	4.55%	5.57%
2005 Q3	10.85%	4.51%	6.34%
2005 Q4	10.59%	4.77%	5.83%
2006 Q1	10.38%	4.76%	5.62%
2006 Q2	10.63%	5.29%	5.34%
2006 Q3	10.06%	5.09%	4.98%
2006 Q4	10.39%	4.83%	5.55%
2007 Q1	10.39%	4.90%	5.49%
2007 Q2	10.27%	5.07%	5.19%
2007 Q3	10.02%	5.01%	5.01%
2007 Q4	10.39%	4.65%	5.74%
2008 Q1	10.15%	4.40%	5.75%
2008 Q2	10.54%	4.59%	5.94%
2008 Q3	10.38%	4.49%	5.89%
2008 Q4	10.39%	3.97%	6.42%
2009 Q1	10.45%	3.69%	6.76%
2009 Q2	10.58%	4.19%	6.39%
2009 Q3	10.41%	4.28%	6.12%
2009 Q4	10.54%	4.27%	6.28%
2010 Q1	10.45%	4.49%	5.96%
2010 Q2	10.08%	4.20%	5.88%
2010 Q3	10.29%	3.60%	6.69%
2010 Q4	10.34%	3.84%	6.50%
2011 Q1	9.96%	4.32%	5.64%
2011 Q2	10.12%	4.07%	6.05%
2011 Q3	10.36%	3.34%	7.02%
2011 Q4	10.34%	2.75%	7.59%
2012 Q1	10.30%	2.80%	7.51%

Quarterly Risk Premiums for Electric Utilities

1990 - 2021

Quarter	Average Authorized Return on Equity	20 year Treasury Bond Yield	Risk Premium
	[1]	[2]	[3] = [1] - [2]
2012 Q2	9.92%	2.55%	7.36%
2012 Q3	9.78%	2.37%	7.41%
2012 Q4	10.05%	2.46%	7.59%
2013 Q1	9.74%	2.75%	6.99%
2013 Q2	9.84%	2.78%	7.06%
2013 Q3	9.83%	3.44%	6.39%
2013 Q4	9.82%	3.50%	6.32%
2014 Q1	9.57%	3.42%	6.16%
2014 Q2	9.83%	3.18%	6.65%
2014 Q3	9.77%	3.01%	6.76%
2014 Q4	9.78%	2.69%	7.08%
2015 Q1	9.66%	2.32%	7.34%
2015 Q2	9.51%	2.62%	6.89%
2015 Q3	9.47%	2.65%	6.82%
2015 Q4	9.65%	2.60%	7.05%
2016 Q1	9.70%	2.32%	7.38%
2016 Q2	9.41%	2.15%	7.26%
2016 Q3	9.76%	1.91%	7.85%
2016 Q4	9.55%	2.52%	7.04%
2017 Q1	9.61%	2.78%	6.83%
2017 Q2	9.61%	2.64%	6.97%
2017 Q3	9.73%	2.58%	7.15%
2017 Q4	9.74%	2.62%	7.12%
2018 Q1	9.59%	2.91%	6.68%
2018 Q2	9.57%	3.00%	6.58%
2018 Q3	9.66%	3.00%	6.66%
2018 Q4	9.44%	3.17%	6.27%
2019 Q1	9.57%	2.85%	6.71%
2019 Q2	9.58%	2.58%	6.99%
2019 Q3	9.57%	2.08%	7.49%
2019 Q4	9.74%	2.10%	7.65%
2020 Q1	9.45%	1.71%	7.74%
2020 Q2	9.52%	1.15%	8.37%
2020 Q3	9.34%	1.15%	8.20%
2020 Q4	9.32%	1.40%	7.91%
2021 Q1	9.30%	1.76%	7.55%

Sources:
[1]: S&P Markte Intelligence as of 02/28/2021.
[2]: Bloomberg as of 2/28/2020.

Schedule No. BV-1

Table of Contents

Schedule No. BV-2

Sample

Classification of Companies by Assets

Company	Company Category
Amer. States Water	R
Amer. Water Works	R
Artesian Res Corp	R
Atmos Energy	R
California Water	R
Chesapeake Utilities	R
Essential Utilities	R
Global Water Resources Inc	R
Middlesex Water	R
New Jersey Resources	MR
NiSource Inc.	R
Northwest Natural	R
ONE Gas Inc.	R
SJW Group	R
South Jersey Inds.	R
Southwest Gas	R
Spire Inc.	R
York Water Co. (The)	R

Sources and Notes:
Calculations based on EEI definitions and Company 10K filings:
R = Regulated (greater than 80 percent of total assets are regulated).
MR = Mostly Regulated (Less than 80 percent of total assets are regulated).

Schedule No. BV-3

Market Value of the Sample

Panel A: Amer. States Water

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$642	$642	$602	$558	$530	$494	$466	[a]
Shares Outstanding (in millions) - Common	37	37	37	37	37	37	37	[b]
Price per Share - Common	$74	$78	$87	$67	$56	$45	$42	[c]
Market Value of Common Equity	$2,722	$2,874	$3,189	$2,466	$2,055	$1,662	$1,533	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$2,722	$2,874	$3,189	$2,466	$2,055	$1,662	$1,533	[f]= [d] + [e]
Market to Book Value of Common Equity	4.24	4.48	5.30	4.42	3.88	3.36	3.29	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$157	$157	$122	$131	$155	$167	$133	[j]
Current Liabilities	$119	$119	$116	$147	$157	$178	$124	[k]
Current Portion of Long-Term Debt	$2	$2	$2	$40	$0	$0	$0	[l]
Net Working Capital	$41	$41	$9	$25	($1)	($11)	$10	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$5	$0	$59	$90	$28	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$1	$11	$0	[o] = See Sources and Notes.
Long-Term Debt	$584	$584	$493	$377	$321	$321	$321	[p]
Book Value of Long-Term Debt	$587	$587	$495	$417	$322	$332	$321	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$560	$560	$376	$388	$424	$424	$404	
Carrying Amount	$444	$444	$285	$325	$325	$326	$326	
Adjustment to Book Value of Long-Term Debt	$115	$115	$91	$63	$99	$98	$78	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$702	$702	$586	$480	$421	$430	$399	[s] = [q] + [r].
Market Value of Debt	$702	$702	$586	$480	$421	$430	$399	[t] = [s].
MARKET VALUE OF FIRM	$3,424	$3,576	$3,775	$2,946	$2,476	$2,091	$1,933	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	79.50%	80.37%	84.48%	83.71%	83.00%	79.44%	79.34%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	20.50%	19.63%	15.52%	16.29%	17.00%	20.56%	20.66%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel B: Amer. Water Works

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$6,454	$6,454	$6,121	$5,864	$5,385	$5,218	$5,049	[a]
Shares Outstanding (in millions) - Common	181	181	181	181	178	178	178	[b]
Price per Share - Common	$143	$150	$121	$93	$91	$73	$59	[c]
Market Value of Common Equity	$25,862	$27,177	$21,963	$16,789	$16,150	$12,972	$10,497	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$25,862	$27,177	$21,963	$16,789	$16,150	$12,972	$10,497	[f]= [d] + [e]
Market to Book Value of Common Equity	4.01	4.21	3.59	2.86	3.00	2.49	2.08	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,906	$1,906	$1,285	$781	$720	$784	$657	[j]
Current Liabilities	$2,881	$2,881	$2,045	$2,094	$2,325	$2,392	$1,533	[k]
Current Portion of Long-Term Debt	$342	$342	$42	$71	$322	$574	$54	[l]
Net Working Capital	($633)	($633)	($718)	($1,242)	($1,283)	($1,034)	($822)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,282	$1,282	$786	$964	$905	$849	$628	[n]
Adjusted Short-Term Debt	$633	$633	$718	$964	$905	$849	$628	[o] = See Sources and Notes.
Long-Term Debt	$9,414	$9,414	$8,733	$7,576	$6,498	$5,760	$5,874	[p]
Book Value of Long-Term Debt	$10,389	$10,389	$9,493	$8,611	$7,725	$7,183	$6,556	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$11,807	$11,807	$9,770	$7,921	$7,643	$7,044	$6,757	
Carrying Amount	$9,656	$9,656	$8,664	$7,638	$6,809	$6,320	$5,914	
Adjustment to Book Value of Long-Term Debt	$2,151	$2,151	$1,106	$283	$834	$724	$843	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$12,540	$12,540	$10,599	$8,894	$8,559	$7,907	$7,399	[s] = [q] + [r].
Market Value of Debt	$12,540	$12,540	$10,599	$8,894	$8,559	$7,907	$7,399	[t] = [s].
MARKET VALUE OF FIRM	$38,402	$39,717	$32,562	$25,683	$24,709	$20,879	$17,896	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	67.35%	68.43%	67.45%	65.37%	65.36%	62.13%	58.65%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	32.65%	31.57%	32.55%	34.63%	34.64%	37.87%	41.35%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel C: Artesian Res Corp

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$169	$169	$160	$153	$147	$139	$132	[a]
Shares Outstanding (in millions) - Common	9	9	9	9	9	9	9	[b]
Price per Share - Common	$40	$38	$37	$36	$38	$32	$27	[c]
Market Value of Common Equity	$376	$354	$346	$329	$353	$294	$245	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$376	$354	$346	$329	$353	$294	$245	[f]= [d] + [e]
Market to Book Value of Common Equity	2.22	2.09	2.16	2.15	2.41	2.11	1.85	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$18	$18	$14	$16	$19	$15	$14	[j]
Current Liabilities	$44	$44	$26	$38	$28	$19	$22	[k]
Current Portion of Long-Term Debt	$2	$2	$2	$2	$1	$1	$1	[l]
Net Working Capital	($24)	($24)	($10)	($20)	($8)	($3)	($7)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$27	$27	$8	$16	$10	$7	$11	[n]
Adjusted Short-Term Debt	$24	$24	$8	$16	$8	$3	$7	[o] = See Sources and Notes.
Long-Term Debt	$143	$143	$145	$116	$106	$102	$104	[p]
Book Value of Long-Term Debt	$169	$169	$154	$134	$115	$107	$112	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$171	$171	$158	$117	$111	$112	$120	
Carrying Amount	$144	$144	$146	$118	$107	$104	$105	
Adjustment to Book Value of Long-Term Debt	$27	$27	$12	($1)	$4	$8	$15	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$196	$196	$166	$133	$119	$115	$127	[s] = [q] + [r].
Market Value of Debt	$196	$196	$166	$133	$119	$115	$127	[t] = [s].
MARKET VALUE OF FIRM	$572	$550	$511	$462	$471	$409	$372	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	65.70%	64.34%	67.60%	71.21%	74.83%	71.83%	65.85%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	34.30%	35.66%	32.40%	28.79%	25.17%	28.17%	34.15%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel D: Atmos Energy

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$7,213	$7,213	$6,128	$5,348	$4,564	$3,699	$3,272	[a]
Shares Outstanding (in millions) - Common	128	128	122	117	111	105	102	[b]
Price per Share - Common	$95	$96	$109	$95	$88	$74	$63	[c]
Market Value of Common Equity	$12,156	$12,274	$13,387	$11,090	$9,729	$7,778	$6,398	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$12,156	$12,274	$13,387	$11,090	$9,729	$7,778	$6,398	[f]= [d] + [e]
Market to Book Value of Common Equity	1.69	1.70	2.18	2.07	2.13	2.10	1.96	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,192	$1,192	$812	$913	$779	$979	$863	[j]
Current Liabilities	$798	$798	$845	$1,455	$959	$1,950	$1,515	[k]
Current Portion of Long-Term Debt	$0	$0	$30	$575	$0	$250	$0	[l]
Net Working Capital	$395	$395	($3)	$32	($181)	($720)	($652)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$0	$337	$941	$763	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$181	$720	$652	[o] = See Sources and Notes.
Long-Term Debt	$5,125	$5,125	$4,528	$3,085	$3,067	$2,314	$2,455	[p]
Book Value of Long-Term Debt	$5,125	$5,125	$4,558	$3,660	$3,248	$3,285	$3,107	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$6,295	$6,295	$4,216	$3,162	$3,382	$2,845	$2,669	
Carrying Amount	$5,160	$5,160	$3,560	$3,085	$3,085	$2,460	$2,460	
Adjustment to Book Value of Long-Term Debt	$1,135	$1,135	$656	$77	$297	$385	$209	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$6,260	$6,260	$5,214	$3,736	$3,545	$3,670	$3,317	[s] = [q] + [r].
Market Value of Debt	$6,260	$6,260	$5,214	$3,736	$3,545	$3,670	$3,317	[t] = [s].
MARKET VALUE OF FIRM	$18,416	$18,534	$18,602	$14,827	$13,274	$11,448	$9,715	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	66.01%	66.23%	71.97%	74.80%	73.29%	67.95%	65.86%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	33.99%	33.77%	28.03%	25.20%	26.71%	32.05%	34.14%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel E: California Water

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$921	$921	$780	$730	$699	$659	$642	[a]
Shares Outstanding (in millions) - Common	50	50	49	48	48	48	48	[b]
Price per Share - Common	$55	$53	$51	$47	$44	$34	$23	[c]
Market Value of Common Equity	$2,747	$2,672	$2,472	$2,266	$2,097	$1,641	$1,116	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$2,747	$2,672	$2,472	$2,266	$2,097	$1,641	$1,116	[f]= [d] + [e]
Market to Book Value of Common Equity	2.98	2.90	3.17	3.10	3.00	2.49	1.74	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$266	$266	$185	$189	$228	$142	$128	[j]
Current Liabilities	$589	$589	$359	$321	$491	$250	$148	[k]
Current Portion of Long-Term Debt	$7	$7	$23	$105	$16	$26	$6	[l]
Net Working Capital	($316)	($316)	($151)	($28)	($247)	($82)	($14)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$370	$370	$175	$65	$275	$97	$34	[n]
Adjusted Short-Term Debt	$316	$316	$151	$28	$247	$82	$14	[o] = See Sources and Notes.
Long-Term Debt	$795	$795	$800	$710	$516	$532	$508	[p]
Book Value of Long-Term Debt	$1,118	$1,118	$974	$842	$779	$640	$528	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$944	$944	$873	$850	$607	$631	$600	
Carrying Amount	$786	$786	$809	$815	$532	$558	$519	
Adjustment to Book Value of Long-Term Debt	$158	$158	$64	$35	$76	$73	$82	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,276	$1,276	$1,038	$877	$855	$712	$610	[s] = [q] + [r].
Market Value of Debt	$1,276	$1,276	$1,038	$877	$855	$712	$610	[t] = [s].
MARKET VALUE OF FIRM	$4,022	$3,948	$3,509	$3,143	$2,952	$2,353	$1,725	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	68.28%	67.68%	70.43%	72.09%	71.05%	69.73%	64.65%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	31.72%	32.32%	29.57%	27.91%	28.95%	30.27%	35.35%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel F: Chesapeake Utilities

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$697	$697	$562	$518	$486	$446	$358	[a]
Shares Outstanding (in millions) - Common	17	17	16	16	16	16	15	[b]
Price per Share - Common	$117	$107	$96	$86	$79	$68	$56	[c]
Market Value of Common Equity	$2,049	$1,869	$1,569	$1,403	$1,293	$1,104	$851	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$2,049	$1,869	$1,569	$1,403	$1,293	$1,104	$851	[f]= [d] + [e]
Market to Book Value of Common Equity	2.94	2.68	2.79	2.71	2.66	2.48	2.38	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$136	$136	$135	$192	$179	$141	$112	[j]
Current Liabilities	$329	$329	$423	$528	$413	$334	$280	[k]
Current Portion of Long-Term Debt	$15	$15	$47	$12	$9	$12	$9	[l]
Net Working Capital	($177)	($177)	($241)	($325)	($225)	($181)	($159)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$176	$176	$247	$294	$251	$210	$173	[n]
Adjusted Short-Term Debt	$176	$176	$241	$294	$225	$181	$159	[o] = See Sources and Notes.
Long-Term Debt	$518	$518	$450	$316	$197	$137	$149	[p]
Book Value of Long-Term Debt	$709	$709	$739	$622	$432	$330	$317	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$549	$549	$505	$324	$215	$162	$165	
Carrying Amount	$523	$523	$487	$327	$205	$146	$154	
Adjustment to Book Value of Long-Term Debt	$26	$26	$18	($3)	$10	$16	$11	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$735	$735	$757	$619	$442	$345	$328	[s] = [q] + [r].
Market Value of Debt	$735	$735	$757	$619	$442	$345	$328	[t] = [s].
MARKET VALUE OF FIRM	$2,784	$2,604	$2,326	$2,022	$1,735	$1,450	$1,180	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	73.60%	71.78%	67.45%	69.38%	74.53%	76.17%	72.17%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	26.40%	28.22%	32.55%	30.62%	25.47%	23.83%	27.83%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel G: Essential Utilities

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$4,684	$4,684	$3,881	$2,009	$1,958	$1,850	$1,726	[a]
Shares Outstanding (in millions) - Common	245	245	221	178	178	177	177	[b]
Price per Share - Common	$44	$47	$46	$34	$38	$30	$30	[c]
Market Value of Common Equity	$10,681	$11,431	$10,168	$6,127	$6,795	$5,345	$5,248	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$10,681	$11,431	$10,168	$6,127	$6,795	$5,345	$5,248	[f]= [d] + [e]
Market to Book Value of Common Equity	2.28	2.44	2.62	3.05	3.47	2.89	3.04	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$380	$380	$2,015	$147	$131	$129	$128	[j]
Current Liabilities	$604	$604	$323	$399	$284	$302	$193	[k]
Current Portion of Long-Term Debt	$92	$92	$106	$145	$114	$151	$36	[l]
Net Working Capital	($132)	($132)	$1,798	($107)	($39)	($22)	($29)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$122	$122	$37	$24	$25	$7	$17	[n]
Adjusted Short-Term Debt	$122	$122	$0	$24	$25	$7	$17	[o] = See Sources and Notes.
Long-Term Debt	$5,563	$5,563	$2,955	$2,398	$2,008	$1,738	$1,720	[p]
Book Value of Long-Term Debt	$5,778	$5,778	$3,061	$2,567	$2,147	$1,895	$1,773	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$0	$0	$0	$0	$0	$0	$0	
Carrying Amount	$0	$0	$0	$0	$0	$0	$0	
Adjustment to Book Value of Long-Term Debt	$0	$0	$0	$0	$0	$0	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$5,778	$5,778	$3,061	$2,567	$2,147	$1,895	$1,773	[s] = [q] + [r].
Market Value of Debt	$5,778	$5,778	$3,061	$2,567	$2,147	$1,895	$1,773	[t] = [s].
MARKET VALUE OF FIRM	$16,459	$17,209	$13,229	$8,694	$8,942	$7,240	$7,021	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	64.90%	66.43%	76.86%	70.47%	75.99%	73.83%	74.75%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	35.10%	33.57%	23.14%	29.53%	24.01%	26.17%	25.25%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel H: Global Water Resources Inc

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$32	$32	$25	$28	$15	$15	$20	[a]
Shares Outstanding (in millions) - Common	23	23	22	22	20	20	18	[b]
Price per Share - Common	$17	$15	$13	$10	$9	$9	N/A	[c]
Market Value of Common Equity	$383	$334	$279	$218	$182	$174	N/A	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$383	$334	$279	$218	$182	$174	N/A	[f]= [d] + [e]
Market to Book Value of Common Equity	11.91	10.39	11.31	7.81	12.26	11.60	N/A	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$23	$23	$12	$17	$10	$25	$19	[j]
Current Liabilities	$12	$12	$10	$10	$9	$11	$11	[k]
Current Portion of Long-Term Debt	$2	$2	$0	$0	$0	$0	$2	[l]
Net Working Capital	$13	$13	$2	$8	$1	$14	$10	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$0	$0	$0	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$113	$113	$115	$115	$114	$114	$102	[p]
Book Value of Long-Term Debt	$115	$115	$115	$115	$114	$114	$104	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$128	$128	$121	$108	$116	$108	$117	
Carrying Amount	$113	$113	$115	$115	$114	$115	$105	
Adjustment to Book Value of Long-Term Debt	$15	$15	$6	($7)	$1	($7)	$12	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$130	$130	$121	$108	$116	$108	$116	[s] = [q] + [r].
Market Value of Debt	$130	$130	$121	$108	$116	$108	$116	[t] = [s].
MARKET VALUE OF FIRM	$513	$464	$400	$326	$298	$282	N/A	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	74.72%	72.04%	69.70%	66.86%	61.14%	61.74%	N/A	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	N/A	[w] = [i] / [u].
Debt - Market Value Ratio	25.28%	27.96%	30.30%	33.14%	38.86%	38.26%	N/A	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel I: Middlesex Water

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$346	$346	$324	$249	$229	$218	$207	[a]
Shares Outstanding (in millions) - Common	17	17	17	16	16	16	16	[b]
Price per Share - Common	$78	$72	$63	$53	$41	$42	$26	[c]
Market Value of Common Equity	$1,366	$1,264	$1,104	$876	$670	$691	$428	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$1,366	$1,264	$1,104	$876	$670	$691	$428	[f]= [d] + [e]
Market to Book Value of Common Equity	3.95	3.65	3.41	3.52	2.92	3.16	2.07	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$2	$2	$2	$2	$2	$2	$2	[h]
Market Value of Preferred Equity	$2	$2	$2	$2	$2	$2	$2	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$34	$34	$29	$31	$29	$27	$24	[j]
Current Liabilities	$57	$57	$65	$94	$65	$47	$28	[k]
Current Portion of Long-Term Debt	$8	$8	$8	$7	$7	$6	$6	[l]
Net Working Capital	($15)	($15)	($28)	($56)	($28)	($14)	$2	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$2	$2	$20	$49	$28	$12	$3	[n]
Adjusted Short-Term Debt	$2	$2	$20	$49	$28	$12	$0	[o] = See Sources and Notes.
Long-Term Debt	$278	$278	$237	$153	$139	$135	$133	[p]
Book Value of Long-Term Debt	$288	$288	$264	$209	$174	$153	$139	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$159	$159	$161	$103	$98	$85	$88	
Carrying Amount	$148	$148	$151	$101	$95	$83	$86	
Adjustment to Book Value of Long-Term Debt	$12	$12	$10	$1	$3	$2	$3	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$300	$300	$274	$210	$177	$155	$141	[s] = [q] + [r].
Market Value of Debt	$300	$300	$274	$210	$177	$155	$141	[t] = [s].
MARKET VALUE OF FIRM	$1,668	$1,566	$1,380	$1,089	$849	$848	$571	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	81.90%	80.72%	79.97%	80.48%	78.91%	81.47%	74.82%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.12%	0.13%	0.15%	0.22%	0.29%	0.29%	0.43%	[w] = [i] / [u].
Debt - Market Value Ratio	17.97%	19.15%	19.88%	19.29%	20.80%	18.25%	24.76%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel J: New Jersey Resources

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$1,698	$1,698	$1,828	$1,497	$1,348	$1,185	$1,144	[a]
Shares Outstanding (in millions) - Common	96	96	90	89	87	86	86	[b]
Price per Share - Common	$41	$35	$44	$48	$40	$36	$31	[c]
Market Value of Common Equity	$3,902	$3,338	$3,977	$4,241	$3,536	$3,119	$2,663	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,902	$3,338	$3,977	$4,241	$3,536	$3,119	$2,663	[f]= [d] + [e]
Market to Book Value of Common Equity	2.30	1.97	2.18	2.83	2.62	2.63	2.33	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$609	$609	$693	$1,050	$826	$815	$589	[j]
Current Liabilities	$519	$519	$806	$999	$991	$823	$575	[k]
Current Portion of Long-Term Debt	$31	$31	$26	$125	$166	$97	$11	[l]
Net Working Capital	$122	$122	($87)	$176	$1	$89	$25	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$134	$134	$391	$372	$373	$285	$211	[n]
Adjusted Short-Term Debt	$0	$0	$87	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$2,370	$2,370	$1,657	$1,185	$1,001	$1,027	$848	[p]
Book Value of Long-Term Debt	$2,401	$2,401	$1,770	$1,310	$1,167	$1,124	$859	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,455	$2,455	$984	$669	$673	$732	$584	
Carrying Amount	$2,103	$2,103	$893	$672	$672	$708	$583	
Adjustment to Book Value of Long-Term Debt	$352	$352	$91	($3)	$1	$24	$1	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,754	$2,754	$1,861	$1,307	$1,168	$1,147	$861	[s] = [q] + [r].
Market Value of Debt	$2,754	$2,754	$1,861	$1,307	$1,168	$1,147	$861	[t] = [s].
MARKET VALUE OF FIRM	$6,656	$6,091	$5,838	$5,548	$4,705	$4,266	$3,524	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.63%	54.79%	68.12%	76.45%	75.17%	73.11%	75.58%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	41.37%	45.21%	31.88%	23.55%	24.83%	26.89%	24.42%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel K: NiSource Inc.

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$4,872	$4,872	$5,107	$4,871	$4,320	$4,071	$3,844	[a]
Shares Outstanding (in millions) - Common	392	392	382	372	337	323	319	[b]
Price per Share - Common	$24	$22	$27	$26	$26	$22	$19	[c]
Market Value of Common Equity	$9,224	$8,793	$10,437	$9,805	$8,714	$7,144	$6,128	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$9,224	$8,793	$10,437	$9,805	$8,714	$7,144	$6,128	[f]= [d] + [e]
Market to Book Value of Common Equity	1.89	1.80	2.04	2.01	2.02	1.75	1.59	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$880	$880	$880	$880	$0	$0	$0	[h]
Market Value of Preferred Equity	$880	$880	$880	$880	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,659	$1,659	$1,854	$2,055	$1,763	$1,762	$1,577	[j]
Current Liabilities	$2,279	$2,279	$3,746	$4,037	$3,178	$3,452	$2,658	[k]
Current Portion of Long-Term Debt	$34	$34	$27	$50	$284	$363	$434	[l]
Net Working Capital	($586)	($586)	($1,865)	($1,931)	($1,131)	($1,327)	($647)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$503	$503	$1,773	$1,977	$1,206	$1,488	$567	[n]
Adjusted Short-Term Debt	$503	$503	$1,773	$1,931	$1,131	$1,327	$567	[o] = See Sources and Notes.
Long-Term Debt	$9,250	$9,250	$7,908	$7,313	$7,675	$6,058	$5,949	[p]
Book Value of Long-Term Debt	$9,786	$9,786	$9,708	$9,295	$9,090	$7,748	$6,950	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$11,034	$11,034	$8,764	$7,228	$8,603	$7,064	$6,976	
Carrying Amount	$9,243	$9,243	$7,870	$7,155	$7,797	$6,421	$6,382	
Adjustment to Book Value of Long-Term Debt	$1,791	$1,791	$895	$73	$807	$643	$594	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$11,577	$11,577	$10,602	$9,368	$9,897	$8,391	$7,543	[s] = [q] + [r].
Market Value of Debt	$11,577	$11,577	$10,602	$9,368	$9,897	$8,391	$7,543	[t] = [s].
MARKET VALUE OF FIRM	$21,681	$21,251	$21,919	$20,053	$18,611	$15,536	$13,671	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	42.54%	41.38%	47.61%	48.90%	46.82%	45.99%	44.82%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	4.06%	4.14%	4.01%	4.39%	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	53.40%	54.48%	48.37%	46.71%	53.18%	54.01%	55.18%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel L: Northwest Natural

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$889	$889	$866	$763	$743	$850	$781	[a]
Shares Outstanding (in millions) - Common	31	31	30	29	29	29	27	[b]
Price per Share - Common	$53	$48	$72	$63	$62	$60	$50	[c]
Market Value of Common Equity	$1,609	$1,459	$2,184	$1,832	$1,771	$1,726	$1,369	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$1,609	$1,459	$2,184	$1,832	$1,771	$1,726	$1,369	[f]= [d] + [e]
Market to Book Value of Common Equity	1.81	1.64	2.52	2.40	2.38	2.03	1.75	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$323	$323	$294	$296	$270	$288	$331	[j]
Current Liabilities	$627	$627	$482	$509	$382	$275	$478	[k]
Current Portion of Long-Term Debt	$96	$96	$77	$30	$97	$40	$25	[l]
Net Working Capital	($207)	($207)	($111)	($183)	($15)	$54	($122)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$305	$305	$149	$218	$54	$53	$270	[n]
Adjusted Short-Term Debt	$207	$207	$111	$183	$15	$0	$122	[o] = See Sources and Notes.
Long-Term Debt	$941	$941	$807	$706	$683	$679	$569	[p]
Book Value of Long-Term Debt	$1,245	$1,245	$995	$919	$795	$719	$716	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$920	$920	$920	$760	$853	$793	$667	
Carrying Amount	$917	$917	$844	$734	$780	$719	$602	
Adjustment to Book Value of Long-Term Debt	$3	$3	$76	$26	$73	$74	$65	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,247	$1,247	$1,071	$946	$869	$793	$782	[s] = [q] + [r].
Market Value of Debt	$1,247	$1,247	$1,071	$946	$869	$793	$782	[t] = [s].
MARKET VALUE OF FIRM	$2,856	$2,706	$3,256	$2,778	$2,640	$2,519	$2,151	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.34%	53.91%	67.10%	65.96%	67.09%	68.51%	63.65%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	43.66%	46.09%	32.90%	34.04%	32.91%	31.49%	36.35%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel M: ONE Gas Inc.

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$2,233	$2,233	$2,129	$2,043	$1,960	$1,888	$1,842	[a]
Shares Outstanding (in millions) - Common	53	53	53	53	52	52	52	[b]
Price per Share - Common	$75	$78	$92	$83	$75	$64	$49	[c]
Market Value of Common Equity	$3,998	$4,150	$4,876	$4,340	$3,904	$3,324	$2,577	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,998	$4,150	$4,876	$4,340	$3,904	$3,324	$2,577	[f]= [d] + [e]
Market to Book Value of Common Equity	1.79	1.86	2.29	2.12	1.99	1.76	1.40	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$540	$540	$506	$543	$589	$569	$483	[j]
Current Liabilities	$797	$797	$873	$699	$1,193	$444	$304	[k]
Current Portion of Long-Term Debt	$7	$7	$7	$300	$0	$0	$0	[l]
Net Working Capital	($250)	($250)	($360)	$144	($604)	$125	$179	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$418	$418	$517	$300	$357	$145	$13	[n]
Adjusted Short-Term Debt	$250	$250	$360	$0	$357	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,613	$1,613	$1,314	$1,285	$1,193	$1,192	$1,192	[p]
Book Value of Long-Term Debt	$1,870	$1,870	$1,681	$1,585	$1,550	$1,192	$1,192	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,000	$2,000	$1,500	$1,400	$1,300	$1,200	$1,200	
Carrying Amount	$1,600	$1,600	$1,286	$1,300	$1,200	$1,200	$1,200	
Adjustment to Book Value of Long-Term Debt	$400	$400	$214	$100	$100	$0	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,270	$2,270	$1,894	$1,685	$1,650	$1,192	$1,192	[s] = [q] + [r].
Market Value of Debt	$2,270	$2,270	$1,894	$1,685	$1,650	$1,192	$1,192	[t] = [s].
MARKET VALUE OF FIRM	$6,269	$6,420	$6,771	$6,025	$5,555	$4,517	$3,768	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	63.78%	64.64%	72.02%	72.03%	70.29%	73.60%	68.38%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	36.22%	35.36%	27.98%	27.97%	29.71%	26.40%	31.62%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel N: SJW Group

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$917	$917	$890	$889	$463	$422	$384	[a]
Shares Outstanding (in millions) - Common	29	29	28	28	21	20	20	[b]
Price per Share - Common	$61	$68	$71	$55	$64	$56	$30	[c]
Market Value of Common Equity	$1,739	$1,953	$2,013	$1,566	$1,304	$1,143	$602	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$1,739	$1,953	$2,013	$1,566	$1,304	$1,143	$602	[f]= [d] + [e]
Market to Book Value of Common Equity	1.90	2.13	2.26	1.76	2.81	2.71	1.57	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$127	$127	$122	$503	$67	$100	$73	[j]
Current Liabilities	$351	$351	$235	$164	$85	$64	$80	[k]
Current Portion of Long-Term Debt	$76	$76	$22	$0	$0	$0	$3	[l]
Net Working Capital	($147)	($147)	($90)	$339	($18)	$36	($3)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$175	$175	$117	$100	$25	$14	$35	[n]
Adjusted Short-Term Debt	$147	$147	$90	$0	$18	$0	$3	[o] = See Sources and Notes.
Long-Term Debt	$1,288	$1,288	$1,284	$431	$431	$433	$377	[p]
Book Value of Long-Term Debt	$1,511	$1,511	$1,396	$431	$449	$433	$383	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,571	$1,571	$1,396	$490	$538	$502	$500	
Carrying Amount	$1,288	$1,288	$1,284	$431	$431	$433	$381	
Adjustment to Book Value of Long-Term Debt	$283	$283	$112	$59	$107	$69	$119	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,794	$1,794	$1,509	$490	$556	$502	$503	[s] = [q] + [r].
Market Value of Debt	$1,794	$1,794	$1,509	$490	$556	$502	$503	[t] = [s].
MARKET VALUE OF FIRM	$3,534	$3,747	$3,521	$2,056	$1,860	$1,645	$1,105	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	49.23%	52.12%	57.16%	76.17%	70.09%	69.47%	54.51%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	50.77%	47.88%	42.84%	23.83%	29.91%	30.53%	45.49%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel O: South Jersey Inds.

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$1,661	$1,661	$1,424	$1,267	$1,192	$1,289	$1,038	[a]
Shares Outstanding (in millions) - Common	101	101	92	86	80	79	71	[b]
Price per Share - Common	$24	$22	$32	$29	$32	$34	$23	[c]
Market Value of Common Equity	$2,409	$2,232	$2,965	$2,473	$2,516	$2,719	$1,648	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$2,409	$2,232	$2,965	$2,473	$2,516	$2,719	$1,648	[f]= [d] + [e]
Market to Book Value of Common Equity	1.45	1.34	2.08	1.95	2.11	2.11	1.59	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$507	$507	$653	$663	$439	$473	$431	[j]
Current Liabilities	$1,164	$1,164	$1,732	$1,581	$883	$953	$832	[k]
Current Portion of Long-Term Debt	$143	$143	$469	$734	$64	$232	$29	[l]
Net Working Capital	($513)	($513)	($610)	($184)	($380)	($247)	($372)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$596	$596	$849	$271	$346	$296	$432	[n]
Adjusted Short-Term Debt	$513	$513	$610	$184	$346	$247	$372	[o] = See Sources and Notes.
Long-Term Debt	$2,778	$2,778	$2,071	$2,107	$1,123	$808	$997	[p]
Book Value of Long-Term Debt	$3,435	$3,435	$3,150	$3,025	$1,533	$1,287	$1,399	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,197	$1,197	$915	$895	$839	$1,081	$1,079	
Carrying Amount	$1,069	$1,069	$965	$893	$822	$1,047	$1,036	
Adjustment to Book Value of Long-Term Debt	$128	$128	($50)	$2	$17	$33	$43	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,562	$3,562	$3,100	$3,026	$1,550	$1,321	$1,442	[s] = [q] + [r].
Market Value of Debt	$3,562	$3,562	$3,100	$3,026	$1,550	$1,321	$1,442	[t] = [s].
MARKET VALUE OF FIRM	$5,971	$5,794	$6,065	$5,500	$4,066	$4,039	$3,090	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	40.34%	38.52%	48.88%	44.97%	61.88%	67.30%	53.34%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	59.66%	61.48%	51.12%	55.03%	38.12%	32.70%	46.66%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel P: Southwest Gas

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$2,675	$2,675	$2,506	$2,252	$1,815	$1,663	$1,594	[a]
Shares Outstanding (in millions) - Common	57	57	55	53	48	47	47	[b]
Price per Share - Common	$67	$61	$76	$79	$81	$76	$53	[c]
Market Value of Common Equity	$3,853	$3,516	$4,161	$4,200	$3,889	$3,606	$2,528	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,853	$3,516	$4,161	$4,200	$3,889	$3,606	$2,528	[f]= [d] + [e]
Market to Book Value of Common Equity	1.44	1.31	1.66	1.86	2.14	2.17	1.59	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$871	$871	$860	$840	$657	$533	$558	[j]
Current Liabilities	$912	$912	$1,080	$939	$816	$628	$535	[k]
Current Portion of Long-Term Debt	$51	$51	$187	$33	$25	$50	$19	[l]
Net Working Capital	$10	$10	($33)	($66)	($134)	($45)	$43	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$107	$107	$211	$152	$215	$0	$18	[n]
Adjusted Short-Term Debt	$0	$0	$33	$66	$134	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$2,810	$2,810	$2,375	$2,107	$1,799	$1,550	$1,551	[p]
Book Value of Long-Term Debt	$2,861	$2,861	$2,595	$2,206	$1,957	$1,600	$1,571	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,628	$2,628	$2,628	$2,173	$1,849	$1,600	$1,571	
Carrying Amount	$2,732	$2,732	$2,300	$2,107	$1,799	$1,550	$1,551	
Adjustment to Book Value of Long-Term Debt	($105)	($105)	$327	$66	$51	$50	$19	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,756	$2,756	$2,922	$2,272	$2,008	$1,650	$1,590	[s] = [q] + [r].
Market Value of Debt	$2,756	$2,756	$2,922	$2,272	$2,008	$1,650	$1,590	[t] = [s].
MARKET VALUE OF FIRM	$6,609	$6,272	$7,083	$6,472	$5,897	$5,256	$4,118	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.30%	56.06%	58.75%	64.89%	65.95%	68.60%	61.39%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	41.70%	43.94%	41.25%	35.11%	34.05%	31.40%	38.61%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel Q: Spire Inc.

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$2,345	$2,345	$2,344	$2,285	$2,079	$1,797	$1,600	[a]
Shares Outstanding (in millions) - Common	52	52	51	51	48	46	43	[b]
Price per Share - Common	$74	$64	$82	$76	$76	$64	$58	[c]
Market Value of Common Equity	$3,803	$3,323	$4,190	$3,859	$3,677	$2,935	$2,533	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,803	$3,323	$4,190	$3,859	$3,677	$2,935	$2,533	[f]= [d] + [e]
Market to Book Value of Common Equity	1.62	1.42	1.79	1.69	1.77	1.63	1.58	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$242	$242	$242	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$242	$242	$242	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$770	$770	$776	$905	$853	$816	$636	[j]
Current Liabilities	$1,547	$1,547	$1,253	$1,563	$1,211	$1,342	$848	[k]
Current Portion of Long-Term Debt	$111	$111	$45	$175	$106	$250	$0	[l]
Net Working Capital	($666)	($666)	($431)	($483)	($253)	($277)	($212)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$696	$696	$519	$626	$584	$506	$377	[n]
Adjusted Short-Term Debt	$666	$666	$431	$483	$253	$277	$212	[o] = See Sources and Notes.
Long-Term Debt	$2,518	$2,518	$2,484	$1,992	$2,030	$1,821	$1,852	[p]
Book Value of Long-Term Debt	$3,294	$3,294	$2,961	$2,650	$2,389	$2,348	$2,063	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$3,120	$3,120	$2,373	$2,074	$2,210	$2,257	$1,944	
Carrying Amount	$2,628	$2,628	$2,123	$2,076	$2,095	$2,084	$1,852	
Adjustment to Book Value of Long-Term Debt	$491	$491	$251	($2)	$115	$173	$93	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,785	$3,785	$3,211	$2,649	$2,504	$2,521	$2,156	[s] = [q] + [r].
Market Value of Debt	$3,785	$3,785	$3,211	$2,649	$2,504	$2,521	$2,156	[t] = [s].
MARKET VALUE OF FIRM	$7,830	$7,351	$7,643	$6,507	$6,181	$5,456	$4,688	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	48.56%	45.21%	54.82%	59.30%	59.49%	53.79%	54.02%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	3.09%	3.29%	3.17%	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	48.34%	51.50%	42.02%	40.70%	40.51%	46.21%	45.98%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel R: York Water Co. (The)

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$143	$143	$134	$126	$119	$114	$109	[a]
Shares Outstanding (in millions) - Common	13	13	13	13	13	13	13	[b]
Price per Share - Common	$49	$47	$46	$33	$34	$39	$25	[c]
Market Value of Common Equity	$634	$619	$597	$427	$441	$496	$318	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$634	$619	$597	$427	$441	$496	$318	[f]= [d] + [e]
Market to Book Value of Common Equity	4.42	4.32	4.45	3.38	3.70	4.35	2.92	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$16	$16	$9	$9	$9	$13	$12	[j]
Current Liabilities	$12	$12	$15	$11	$9	$8	$6	[k]
Current Portion of Long-Term Debt	$0	$0	$7	$0	$0	$0	$0	[l]
Net Working Capital	$4	$4	$1	($2)	($0)	$4	$5	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$1	$1	$0	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$1	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$124	$124	$95	$93	$90	$85	$85	[p]
Book Value of Long-Term Debt	$124	$124	$101	$94	$91	$85	$85	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$151	$151	$115	$105	$108	$99	$102	
Carrying Amount	$127	$127	$104	$96	$93	$87	$88	
Adjustment to Book Value of Long-Term Debt	$24	$24	$11	$9	$15	$12	$14	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$148	$148	$112	$103	$106	$96	$99	[s] = [q] + [r].
Market Value of Debt	$148	$148	$112	$103	$106	$96	$99	[t] = [s].
MARKET VALUE OF FIRM	$782	$767	$709	$531	$547	$592	$417	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	81.06%	80.70%	84.21%	80.50%	80.66%	83.75%	76.26%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	18.94%	19.30%	15.79%	19.50%	19.34%	16.25%	23.74%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-4

Sample

Capital Structure Summary of the Sample

Company	DCF Capital Structure			5-Year Average Capital Structure		
	Common Equity - Value Ratio	Preferred Equity - Value Ratio	Debt - Value Ratio	Common Equity - Value Ratio	Preferred Equity - Value Ratio	Debt - Value Ratio
	[1]	[2]	[3]	[4]	[5]	[6]
Amer. States Water	0.79	0.00	0.21	0.82	0.00	0.18
Amer. Water Works	0.67	0.00	0.33	0.66	0.00	0.34
Artesian Res Corp	0.66	0.00	0.34	0.70	0.00	0.30
Atmos Energy	0.66	0.00	0.34	0.71	0.00	0.29
California Water	0.68	0.00	0.32	0.70	0.00	0.30
Chesapeake Utilities	0.74	0.00	0.26	0.72	0.00	0.28
Essential Utilities	0.65	0.00	0.35	0.73	0.00	0.27
Global Water Resources Inc	0.75	0.00	0.25	0.66	0.00	0.34
Middlesex Water	0.82	0.00	0.18	0.80	0.00	0.19
New Jersey Resources	0.59	0.00	0.41	0.70	0.00	0.30
NiSource Inc.	0.43	0.04	0.53	0.46	0.03	0.51
Northwest Natural	0.56	0.00	0.44	0.65	0.00	0.35
ONE Gas Inc.	0.64	0.00	0.36	0.71	0.00	0.29
SJW Group	0.49	0.00	0.51	0.65	0.00	0.35
South Jersey Inds.	0.40	0.00	0.60	0.52	0.00	0.48
Southwest Gas	0.58	0.00	0.42	0.63	0.00	0.37
Spire Inc.	0.49	0.03	0.48	0.55	0.01	0.44
York Water Co. (The)	0.81	0.00	0.19	0.82	0.00	0.18
Combined Sample Average	0.63	0.00	0.36	0.68	0.00	0.32
Water Sample Average	0.70	0.00	0.30	0.73	0.00	0.27
Gas Sample Average	0.56	0.01	0.43	0.63	0.00	0.37

Sources and Notes:
[1], [4]:Workpaper #1 to Schedule No. BV-4.
[2], [5]:Workpaper #2 to Schedule No. BV-4.
[3], [6]:Workpaper #3 to Schedule No. BV-4.
Values in this table may not add up exactly to 1.0 because of rounding.

Schedule No. BV-5

Sample

Estimated Growth Rates of the Sample

	Thomson Reuters IBES Estimate		Value Line			
Company	Long-Term Growth Rate	Number of Estimates	EPS Year 2020 Estimate	EPS Year 2023-2025 Estimate	Annualized Growth Rate	Combined Growth Rate
	[1]	[2]	[3]	[4]	[5]	[6]
Amer. States Water	4.6%	1	2.40	3.05	6.2%	5.4%
Amer. Water Works	8.6%	1	4.25	5.50	6.7%	7.6%
Artesian Res Corp	4.0%	1	n/a	n/a	n/a	4.0%
Atmos Energy	7.0%	3	5.00	6.50	6.8%	6.9%
California Water	10.8%	2	1.90	2.25	4.3%	8.6%
Chesapeake Utilities	4.7%	1	4.25	5.75	7.8%	6.3%
Essential Utilities	6.4%	1	1.65	1.90	3.6%	5.0%
Global Water Resources Inc	15.0%	1	n/a	n/a	n/a	15.0%
Middlesex Water	2.7%	1	2.25	2.70	4.7%	3.7%
New Jersey Resources	6.0%	1	1.65	2.45	10.4%	8.2%
NiSource Inc.	4.4%	1	1.40	2.30	13.2%	8.8%
Northwest Natural	3.1%	1	2.50	3.10	5.5%	4.3%
ONE Gas Inc.	5.0%	1	3.80	5.00	7.1%	6.1%
SJW Group	5.5%	1	2.55	3.65	9.4%	7.4%
South Jersey Inds.	4.4%	1	1.70	2.50	10.1%	7.3%
Southwest Gas	4.0%	1	4.45	6.50	9.9%	7.0%
Spire Inc.	5.7%	2	3.85	5.15	7.5%	6.3%
York Water Co. (The)	4.9%	1	1.35	1.65	5.1%	5.0%

Sources and Notes:
[1] - [2]: Thomson Reuters as of March 31, 2021.
[3] - [4]: From Valueline Investment Analyzer as of March 31, 2021.
[5]: ([4] / [3]) ^ (1/4) - 1.
[6]: ([1] x [2] + [5]) / ([2] + 1).
Weighted average growth rate. If information is missing from one source, the weighted average is based solely on the other source.

Schedule No. BV-6

DCF Cost of Equity of the Sample

Panel A: Simple DCF Method (Quarterly)

Company	Stock Price	Most Recent Dividend	Quarterly Dividend Yield	Combined Long-Term Growth Rate	Quarterly Growth Rate	DCF Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]
Amer. States Water	$73.79	$0.34	0.46%	5.4%	1.3%	7.3%
Amer. Water Works	$142.65	$0.55	0.39%	7.6%	1.9%	9.3%
Artesian Res Corp	$40.16	$0.26	0.65%	4.0%	1.0%	6.7%
Atmos Energy	$94.85	$0.63	0.67%	6.9%	1.7%	9.8%
California Water	$54.57	$0.23	0.43%	8.6%	2.1%	10.4%
Chesapeake Utilities	$117.33	$0.44	0.38%	6.3%	1.5%	7.9%
Essential Utilities	$43.53	$0.25	0.58%	5.0%	1.2%	7.4%
Global Water Resources Ir	$16.97	$0.02	0.15%	15.0%	3.6%	15.7%
Middlesex Water	$78.19	$0.27	0.35%	3.7%	0.9%	5.1%
New Jersey Resources	$40.59	$0.33	0.84%	8.2%	2.0%	11.8%
NiSource Inc.	$23.54	$0.22	0.95%	8.8%	2.1%	12.9%
Northwest Natural	$52.60	$0.48	0.92%	4.3%	1.1%	8.2%
ONE Gas Inc.	$75.20	$0.58	0.78%	6.1%	1.5%	9.4%
SJW Group	$60.91	$0.34	0.57%	7.4%	1.8%	9.9%
South Jersey Inds.	$23.95	$0.30	1.29%	7.3%	1.8%	12.8%
Southwest Gas	$67.37	$0.57	0.86%	7.0%	1.7%	10.6%
Spire Inc.	$73.61	$0.65	0.90%	6.3%	1.5%	10.1%
York Water Co. (The)	$48.51	$0.19	0.39%	5.0%	1.2%	6.7%

Sources and Notes:
[1]: Workpaper #1 to Schedule No. BV-6.
[2]: Workpaper #2 to Schedule No. BV-6.
[3]: ([2] / [1]) x (1 + [5]).
[4]: Schedule No. BV-5, [6].
[5]: {(1 + [4]) ^ (1/4)} - 1.
[6]: {([3] + [5] + 1) ^ 4} - 1.

Schedule No. BV-6

DCF Cost of Equity of the Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	Stock Price	Most Recent Dividend	Combined Long-Term Growth Rate	Growth Rate: Year 6	Growth Rate: Year 7	Growth Rate: Year 8	Growth Rate: Year 9	Growth Rate: Year 10	GDP Long-Term Growth Rate	DCF Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Amer. States Water	$73.79	$0.34	5.4%	5.1%	4.9%	4.6%	4.4%	4.1%	3.9%	6.0%
Amer. Water Works	$142.65	$0.55	7.6%	7.0%	6.4%	5.8%	5.1%	4.5%	3.9%	6.0%
Artesian Res Corp	$40.16	$0.26	4.0%	4.0%	4.0%	4.0%	3.9%	3.9%	3.9%	6.6%
Atmos Energy	$94.85	$0.63	6.9%	6.4%	5.9%	5.4%	4.9%	4.4%	3.9%	7.3%
California Water	$54.57	$0.23	8.6%	7.8%	7.0%	6.3%	5.5%	4.7%	3.9%	6.3%
Chesapeake Utilities	$117.33	$0.44	6.3%	5.9%	5.5%	5.1%	4.7%	4.3%	3.9%	5.7%
Essential Utilities	$43.53	$0.25	5.0%	4.8%	4.6%	4.4%	4.3%	4.1%	3.9%	6.5%
Global Water Resources Inc	$16.97	$0.02	15.0%	13.2%	11.3%	9.5%	7.6%	5.8%	3.9%	5.2%
Middlesex Water	$78.19	$0.27	3.7%	3.7%	3.8%	3.8%	3.8%	3.9%	3.9%	5.3%
New Jersey Resources	$40.59	$0.33	8.2%	7.5%	6.8%	6.0%	5.3%	4.6%	3.9%	8.4%
NiSource Inc.	$23.54	$0.22	8.8%	8.0%	7.2%	6.3%	5.5%	4.7%	3.9%	9.2%
Northwest Natural	$52.60	$0.48	4.3%	4.2%	4.2%	4.1%	4.0%	4.0%	3.9%	7.8%
ONE Gas Inc.	$75.20	$0.58	6.1%	5.7%	5.3%	5.0%	4.6%	4.3%	3.9%	7.6%
SJW Group	$60.91	$0.34	7.4%	6.9%	6.3%	5.7%	5.1%	4.5%	3.9%	6.8%
South Jersey Inds.	$23.95	$0.30	7.3%	6.7%	6.1%	5.6%	5.0%	4.5%	3.9%	10.4%
Southwest Gas	$67.37	$0.57	7.0%	6.5%	5.9%	5.4%	4.9%	4.4%	3.9%	8.2%
Spire Inc.	$73.61	$0.65	6.3%	5.9%	5.5%	5.1%	4.7%	4.3%	3.9%	8.2%
York Water Co. (The)	$48.51	$0.19	5.0%	4.8%	4.6%	4.5%	4.3%	4.1%	3.9%	5.6%

Sources and Notes:
[1]: Workpaper #1 to Schedule No. BV-6.
[2]: Workpaper #2 to Schedule No. BV-6.
[3]: Schedule No. BV-5, [6].
[4]: [3] - {([3] - [9])/ 6}.
[5]: [4] - {([3] - [9])/ 6}.
[6]: [5] - {([3] - [9])/ 6}.
[7]: [6] - {([3] - [9])/ 6}.
[8]: [7] - {([3] - [9])/ 6}.
[9]: BlueChip Economic Indicators, March 2021 This number is assumed to be the perpetual growth rate.
[10]: Workpaper #3 to Schedule No. BV-6.

Schedule No. BV-7

Overall After-Tax DCF Cost of Capital of the Sample

Panel A: Simple DCF Method (Quarterly)

Company	4th Quarter, 2020 S&P Bond Rating	4th Quarter, 2020 Preferred Equity Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	Portland General Electric's Representative Income Tax Rate	Overall Weighted After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Amer. States Water	A	-	7.3%	0.79	-	0.00	3.4%	0.21	27.0%	6.3%
Amer. Water Works	A	-	9.3%	0.67	-	0.00	3.4%	0.33	27.0%	7.1%
Artesian Res Corp	A	-	6.7%	0.66	-	0.00	3.4%	0.34	27.0%	5.2%
Atmos Energy	A	-	9.8%	0.66	-	0.00	3.4%	0.34	27.0%	7.3%
California Water	A	-	10.4%	0.68	-	0.00	3.4%	0.32	27.0%	7.9%
Chesapeake Utilities	A	-	7.9%	0.74	-	0.00	3.4%	0.26	27.0%	6.5%
Essential Utilities	A	-	7.4%	0.65	-	0.00	3.4%	0.35	27.0%	5.7%
Global Water Resources Inc	A	-	15.7%	0.75	-	0.00	3.4%	0.25	27.0%	12.3%
Middlesex Water	A	A	5.1%	0.82	3.4%	0.00	3.4%	0.18	27.0%	4.6%
New Jersey Resources	A	-	11.8%	0.59	-	0.00	3.4%	0.41	27.0%	7.9%
NiSource Inc.	BBB	BBB	12.9%	0.43	3.7%	0.04	3.7%	0.53	27.0%	7.1%
Northwest Natural	BBB	-	8.2%	0.56	-	0.00	3.7%	0.44	27.0%	5.8%
ONE Gas Inc.	A	-	9.4%	0.64	-	0.00	3.4%	0.36	27.0%	6.9%
SJW Group	A	-	9.9%	0.49	-	0.00	3.4%	0.51	27.0%	6.1%
South Jersey Inds.	BBB	-	12.8%	0.40	-	0.00	3.7%	0.60	27.0%	6.8%
Southwest Gas	BBB	-	10.6%	0.58	-	0.00	3.7%	0.42	27.0%	7.3%
Spire Inc.	A	A	10.1%	0.49	3.4%	0.03	3.4%	0.48	27.0%	6.2%
York Water Co. (The)	A	-	6.7%	0.81	-	0.00	3.4%	0.19	27.0%	5.9%
Simple Combined Sample Average			9.6%	0.63	3.5%	0.00	3.4%	0.36	27.0%	6.8%
Simple Gas Sample Average			10.4%	0.56	3.5%	0.01	3.5%	0.43	27.0%	6.9%
Simple Water Sample Average			8.7%	0.70	3.4%	0.00	3.4%	0.30	27.0%	6.8%

Sources and Notes:
[1]: Bloomberg as of March 31, 2021.
[2]: Preferred ratings were assumed equal to debt rating
[3]: Schedule No. BV-6; Panel A, [6].
[4]: Schedule No. BV-4, [1].
[5]: Workpaper #2 to Schedule No. BV-11, Panel C.
[6]: Schedule No. BV-4, [2].
[7]: Workpaper #2 to Schedule No. BV-11, Panel B.
[8]: Schedule No. BV-4, [3].
[9]: Provided by Portland General Electric.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

Schedule No. BV-7

Overall After-Tax DCF Cost of Capital of the Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	4th Quarter, 2020 S&P Bond Rating	4th Quarter, 2020 Preferred Equity Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	Portland General Electric's Representative Income Tax Rate	Overall Weighted After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Amer. States Water	A	-	6.0%	0.79	-	0.00	3.4%	0.21	27.0%	5.3%
Amer. Water Works	A	-	6.0%	0.67	-	0.00	3.4%	0.33	27.0%	4.8%
Artesian Res Corp	A	-	6.6%	0.66	-	0.00	3.4%	0.34	27.0%	5.2%
Atmos Energy	A	-	7.3%	0.66	-	0.00	3.4%	0.34	27.0%	5.6%
California Water	A	-	6.3%	0.68	-	0.00	3.4%	0.32	27.0%	5.1%
Chesapeake Utilities	A	-	5.7%	0.74	-	0.00	3.4%	0.26	27.0%	4.9%
Essential Utilities	A	-	6.5%	0.65	-	0.00	3.4%	0.35	27.0%	5.1%
Global Water Resources Inc	A	-	5.2%	0.75	-	0.00	3.4%	0.25	27.0%	4.5%
Middlesex Water	A	A	5.3%	0.82	3.4%	0.00	3.4%	0.18	27.0%	4.8%
New Jersey Resources	A	-	8.4%	0.59	-	0.00	3.4%	0.41	27.0%	5.9%
NiSource Inc.	BBB	BBB	9.2%	0.43	3.7%	0.04	3.7%	0.53	27.0%	5.5%
Northwest Natural	BBB	-	7.8%	0.56	-	0.00	3.7%	0.44	27.0%	5.6%
ONE Gas Inc.	A	-	7.6%	0.64	-	0.00	3.4%	0.36	27.0%	5.7%
SJW Group	A	-	6.8%	0.49	-	0.00	3.4%	0.51	27.0%	4.6%
South Jersey Inds.	BBB	-	10.4%	0.40	-	0.00	3.7%	0.60	27.0%	5.8%
Southwest Gas	BBB	-	8.2%	0.58	-	0.00	3.7%	0.42	27.0%	5.9%
Spire Inc.	A	A	8.2%	0.49	3.4%	0.03	3.4%	0.48	27.0%	5.3%
York Water Co. (The)	A	-	5.6%	0.81	-	0.00	3.4%	0.19	27.0%	5.0%
Multi-Stage Combined Sample Average			7.1%	0.63	3.5%	0.00	3.4%	0.36	27.0%	5.3%
Multi-Stage Gas Sample Average			8.1%	0.56	3.5%	0.01	3.5%	0.43	27.0%	5.6%
Multi-Stage Water Sample Average			6.0%	0.70	3.4%	0.00	3.4%	0.30	27.0%	4.9%

Sources and Notes:
[1]: Bloomberg as of March 31, 2021.
[2]: Preferred ratings were assumed equal to debt rating
[3]: Schedule No. BV-6, Panel B, [10].
[4]: Schedule No. BV-4, [1].
[5]: Workpaper #2 to Schedule No. BV-11, Panel C.
[6]: Schedule No. BV-4, [2].
[7]: Workpaper #2 to Schedule No. BV-11, Panel B.
[8]: Schedule No. BV-4, [3].
[9]: Provided by Portland General Electric.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

Schedule No. BV-8

DCF Cost of Equity at Portland General Electric's Proposed Capital Structure

Sample

	Overall After - Tax Cost of Capital [1]	Portland General Electric's Representative Regulatory % Debt [2]	Representative Cost of BBB Rated Utility Debt [3]	Portland General Electric's Representative Income Tax Rate [4]	Portland General Electric's Representative Regulatory % Equity [5]	Estimated Return on Equity [6]
Combined Sample						
Simple DCF Quarterly	6.8%	50.0%	3.7%	27.0%	50.0%	10.9%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Rate	5.3%	50.0%	3.7%	27.0%	50.0%	7.8%
Electric Sample						
Simple DCF Quarterly	6.8%	50.0%	3.7%	27.0%	50.0%	10.9%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Rate	4.9%	50.0%	3.7%	27.0%	50.0%	7.1%
Gas Sample						
Simple DCF Quarterly	6.9%	50.0%	3.7%	27.0%	50.0%	11.0%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Rate	5.6%	50.0%	3.7%	27.0%	50.0%	8.5%

Sources and Notes:
[1]: Schedule No. BV-7; Panels A-B, [10].
[2]: Provided by Portland General Electric.
[3]: Based on a BBB rating. Yield from Bloomberg as of March 31, 2021.
[4]: Provided by Portland General Electric.
[5]: Provided by Portland General Electric.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

Schedule No. BV-9 Risk-Free Rates

BCEI Forecast of 10 year U.S. Treasury Yield	**[a]**	**2.10%**
Long-run Average of 20 year U.S. Treasury Yield	[b]	5.01%
Long-run Average of 10 year U.S. Treasury Yield	[c]	4.53%
Maturity Premium	**[d] = [b] - [c]**	**0.50%**
Base Projection of 20 year U.S. Treasury Yield	**[e] = [a] + [d]**	**2.60%**

Sources and Notes:
[a]: Blue Chip Economic Indicators, March 2021. Average projection of 2022 and 2023 Yiel
[b], [c]: Bloomberg as of 3/31/2021, see Workpaper #1 to Schedule No. BV-9.

Schedule No. BV-10

Risk Positioning Cost of Equity of the Sample (Using Value Line Betas)

Panel A: Scenario 1 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%

Company	Long-Term Risk-Free Rate	Value Line Betas	Long-Term Market Risk Premium	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Amer. States Water	2.80%	0.65	7.25%	7.5%	8.0%
Amer. Water Works	2.80%	0.85	7.25%	9.0%	9.2%
Artesian Res Corp	2.80%	0.75	7.25%	8.2%	8.6%
Atmos Energy	2.80%	0.80	7.25%	8.6%	8.9%
California Water	2.80%	0.65	7.25%	7.5%	8.0%
Chesapeake Utilities	2.80%	0.80	7.25%	8.6%	8.9%
Essential Utilities	2.80%	0.95	7.25%	9.7%	9.8%
Global Water Resources Inc	2.80%	0.75	7.25%	8.2%	8.6%
Middlesex Water	2.80%	0.70	7.25%	7.9%	8.3%
New Jersey Resources	2.80%	0.95	7.25%	9.7%	9.8%
NiSource Inc.	2.80%	0.85	7.25%	9.0%	9.2%
Northwest Natural	2.80%	0.80	7.25%	8.6%	8.9%
ONE Gas Inc.	2.80%	0.80	7.25%	8.6%	8.9%
SJW Group	2.80%	0.85	7.25%	9.0%	9.2%
South Jersey Inds.	2.80%	1.05	7.25%	10.4%	10.3%
Southwest Gas	2.80%	0.95	7.25%	9.7%	9.8%
Spire Inc.	2.80%	0.85	7.25%	9.0%	9.2%
York Water Co. (The)	2.80%	0.80	7.25%	8.6%	8.9%

Sources and Notes:
[1], [3]: Villadsen Direct Testimony.
[2]: From Valueline Investment Analyzer as of March 31, 2021.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-10

Risk Positioning Cost of Equity of the Sample (Using Value Line Betas)

Panel B: Scenario 2 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%

Company	Long-Term Risk-Free Rate	Value Line Betas	Long-Term Market Risk Premium	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Amer. States Water	2.80%	0.65	8.00%	8.0%	8.5%
Amer. Water Works	2.80%	0.85	8.00%	9.6%	9.8%
Artesian Res Corp	2.80%	0.75	8.00%	8.8%	9.2%
Atmos Energy	2.80%	0.80	8.00%	9.2%	9.5%
California Water	2.80%	0.65	8.00%	8.0%	8.5%
Chesapeake Utilities	2.80%	0.80	8.00%	9.2%	9.5%
Essential Utilities	2.80%	0.95	8.00%	10.4%	10.5%
Global Water Resources Inc	2.80%	0.75	8.00%	8.8%	9.2%
Middlesex Water	2.80%	0.70	8.00%	8.4%	8.9%
New Jersey Resources	2.80%	0.95	8.00%	10.4%	10.5%
NiSource Inc.	2.80%	0.85	8.00%	9.6%	9.8%
Northwest Natural	2.80%	0.80	8.00%	9.2%	9.5%
ONE Gas Inc.	2.80%	0.80	8.00%	9.2%	9.5%
SJW Group	2.80%	0.85	8.00%	9.6%	9.8%
South Jersey Inds.	2.80%	1.05	8.00%	11.2%	11.1%
Southwest Gas	2.80%	0.95	8.00%	10.4%	10.5%
Spire Inc.	2.80%	0.85	8.00%	9.6%	9.8%
York Water Co. (The)	2.80%	0.80	8.00%	9.2%	9.5%

Sources and Notes:
[1], [3]: Villadsen Direct Testimony.
[2]: From Valueline Investment Analyzer as of March 31, 2021.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-11

Overall After-Tax Risk Positioning Cost of Capital of the Sample (Using Value Line Betas)

Panel A: CAPM Cost of Equity Scenario 1 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%

Company	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity	5-Year Average Common Equity to Market Value Ratio	Weighted - Average Cost of Preferred Equity	5-Year Average Preferred Equity to Market Value Ratio	Weighted-Average Cost of Debt	5-Year Average Debt to Market Value Ratio	Electric's Representative Income Tax Rate	Overall After-Tax Cost of Capital (CAPM)	Overall After-Tax Cost of Capital (ECAPM 1.5%)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Amer. States Water	7.5%	8.0%	0.82	-	0.00	3.4%	0.18	27.0%	6.6%	7.0%
Amer. Water Works	9.0%	9.2%	0.66	-	0.00	3.4%	0.34	27.0%	6.7%	6.9%
Artesian Res Corp	8.2%	8.6%	0.70	-	0.00	3.4%	0.30	27.0%	6.5%	6.8%
Atmos Energy	8.6%	8.9%	0.71	-	0.00	3.4%	0.29	27.0%	6.8%	7.0%
California Water	7.5%	8.0%	0.70	-	0.00	3.4%	0.30	27.0%	6.0%	6.4%
Chesapeake Utilities	8.6%	8.9%	0.72	-	0.00	3.4%	0.28	27.0%	6.9%	7.1%
Essential Utilities	9.7%	9.8%	0.73	-	0.00	3.4%	0.27	27.0%	7.7%	7.8%
Global Water Resources Inc	8.2%	8.6%	0.66	-	0.00	3.4%	0.34	27.0%	6.3%	6.5%
Middlesex Water	7.9%	8.3%	0.80	3.4%	0.00	3.4%	0.19	27.0%	6.8%	7.2%
New Jersey Resources	9.7%	9.8%	0.70	-	0.00	3.4%	0.30	27.0%	7.5%	7.5%
NiSource Inc.	9.0%	9.2%	0.46	3.7%	0.03	3.7%	0.51	27.0%	5.6%	5.7%
Northwest Natural	8.6%	8.9%	0.65	-	0.00	3.7%	0.35	27.0%	6.5%	6.7%
ONE Gas Inc.	8.6%	8.9%	0.71	-	0.00	3.4%	0.29	27.0%	6.8%	7.0%
SJW Group	9.0%	9.2%	0.65	-	0.00	3.4%	0.35	27.0%	6.7%	6.8%
South Jersey Inds.	10.4%	10.3%	0.52	-	0.00	3.7%	0.48	27.0%	6.7%	6.7%
Southwest Gas	9.7%	9.8%	0.63	-	0.00	3.7%	0.37	27.0%	7.1%	7.1%
Spire Inc.	9.0%	9.2%	0.55	3.4%	0.01	3.4%	0.44	27.0%	6.0%	6.1%
York Water Co. (The)	8.6%	8.9%	0.82	-	0.00	3.4%	0.18	27.0%	7.5%	7.7%
Combined Sample Average	8.8%	9.0%	0.68	3.5%	0.00	3.4%	0.32	27.0%	6.7%	6.9%
Gas Sample Average	9.1%	9.3%	0.63	3.5%	0.00	3.5%	0.37	27.0%	6.7%	6.8%
Water Sample Average	8.4%	8.7%	0.73	3.4%	0.00	3.4%	0.27	27.0%	6.8%	7.0%

Sources and Notes:
[1]: Schedule No. BV-10; Panel A, [4].
[2]: Schedule No. BV-10; Panel A, [5].
[3]: Schedule No. BV-4, [4].
[4]: Workpaper #2 to Schedule No. BV-11, Panel C.
[5]: Schedule No. BV-4, [5].
[6]: Workpaper #2 to Schedule No. BV-11, Panel B.
[7]: Schedule No. BV-4, [6].
[8]: Provided by Portland General Electric.
[9] = [1] x [3] + [4] x [5] + [6] x [7] x (1 - [8])
[10] = [2] x [3] + [4] x [5] + [6] x [7] x (1 - [8])

Schedule No. BV-11

Overall After-Tax Risk Positioning Cost of Capital of the Sample (Using Value Line Betas)

Panel B: CAPM Cost of Equity Scenario 2 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%

Company	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity	5-Year Average Common Equity to Market Value Ratio	Weighted - Average Cost of Preferred Equity	5-Year Average Preferred Equity to Market Value Ratio	Weighted- Average Cost of Debt	5-Year Average Debt to Market Value Ratio	Electric's Representative Income Tax Rate	Overall After-Tax Cost of Capital (CAPM)	Overall After-Tax Cost of Capital (ECAPM 1.5%)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	capmlt	ecapmlt2	capm_equity_ratio	average	capm_pref_ratio	average	capm_debt_ratio		CAPM	ECAPM2
Amer. States Water	8.0%	8.5%	0.82	-	0.00	3.4%	0.18	27.0%	7.0%	7.4%
Amer. Water Works	9.6%	9.8%	0.66	-	0.00	3.4%	0.34	27.0%	7.1%	7.3%
Artesian Res Corp	8.8%	9.2%	0.70	-	0.00	3.4%	0.30	27.0%	6.9%	7.2%
Atmos Energy	9.2%	9.5%	0.71	-	0.00	3.4%	0.29	27.0%	7.2%	7.4%
California Water	8.0%	8.5%	0.70	-	0.00	3.4%	0.30	27.0%	6.3%	6.7%
Chesapeake Utilities	9.2%	9.5%	0.72	-	0.00	3.4%	0.28	27.0%	7.3%	7.5%
Essential Utilities	10.4%	10.5%	0.73	-	0.00	3.4%	0.27	27.0%	8.2%	8.3%
Global Water Resources Inc	8.8%	9.2%	0.66	-	0.00	3.4%	0.34	27.0%	6.7%	6.9%
Middlesex Water	8.4%	8.9%	0.80	3.4%	0.00	3.4%	0.19	27.0%	7.2%	7.6%
New Jersey Resources	10.4%	10.5%	0.70	-	0.00	3.4%	0.30	27.0%	8.0%	8.0%
NiSource Inc.	9.6%	9.8%	0.46	3.7%	0.03	3.7%	0.51	27.0%	5.9%	6.0%
Northwest Natural	9.2%	9.5%	0.65	-	0.00	3.7%	0.35	27.0%	6.9%	7.1%
ONE Gas Inc.	9.2%	9.5%	0.71	-	0.00	3.4%	0.29	27.0%	7.2%	7.4%
SJW Group	9.6%	9.8%	0.65	-	0.00	3.4%	0.35	27.0%	7.1%	7.2%
South Jersey Inds.	11.2%	11.1%	0.52	-	0.00	3.7%	0.48	27.0%	7.2%	7.1%
Southwest Gas	10.4%	10.5%	0.63	-	0.00	3.7%	0.37	27.0%	7.5%	7.6%
Spire Inc.	9.6%	9.8%	0.55	3.4%	0.01	3.4%	0.44	27.0%	6.4%	6.5%
York Water Co. (The)	9.2%	9.5%	0.82	-	0.00	3.4%	0.18	27.0%	8.0%	8.2%
Combined Sample Average	9.4%	9.6%	0.68	3.5%	0.00	3.4%	0.32	27.0%	7.1%	7.3%
Gas Sample Average	9.8%	10.0%	0.63	3.5%	0.00	3.5%	0.37	27.0%	7.1%	7.2%
Water Sample Average	9.0%	9.3%	0.73	3.4%	0.00	3.4%	0.27	27.0%	7.2%	7.4%

Sources and Notes:
[1]: Schedule No. BV-10; Panel B, [4].
[2]: Schedule No. BV-10; Panel B, [5].
[3]: Schedule No. BV-4, [4].
[4]: Workpaper #2 to Schedule No. BV-11, Panel C.
[5]: Schedule No. BV-4, [5].
[6]: Workpaper #2 to Schedule No. BV-11, Panel B.
[7]: Schedule No. BV-4, [6].
[8]: Provided by Portland General Electric.
[9] = [1] x [3] + [4] x [5] + [6] x [7] x (1 - [8])
[10] = [2] x [3] + [4] x [5] + [6] x [7] x (1 - [8])

Schedule No. BV-12

Risk Positioning Cost of Equity at Portland General Electric's Proposed Capital Structure

Sample

Using Value Line Betas

	Overall After-Tax Cost of Capital (Scenario 1)	Overall After-Tax Cost of Capital (Scenario 2)	Portland General Electric's Representative Regulatory % Debt	Representative Cost of BBB-Rated Utility Debt	Portland General Electric's Representative Income Tax Rate	Portland General Electric's Regulatory % Preferred Equity	Portland General Electric's Cost of Preferred Equity	Portland General Electric's Representative Regulatory % Equity	Estimated Return on Equity (Scenario 1)	Estimated Return on Equity (Scenario 2)
	[1]	[2]	[3]	[4]	[5]			[6]	[7]	[8]
Combined Sample										
CAPM using Value Line Betas	6.7%	7.1%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	10.7%	11.5%
ECAPM (1.50%) using Value Line Betas	6.9%	7.3%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	11.1%	11.9%
Water Sample										
CAPM using Value Line Betas	6.8%	7.2%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	10.8%	11.6%
ECAPM (1.50%) using Value Line Betas	7.0%	7.4%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	11.3%	12.1%
Gas Sample										
CAPM using Value Line Betas	6.7%	7.1%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	10.6%	11.4%
ECAPM (1.50%) using Value Line Betas	6.8%	7.2%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	10.8%	11.7%

Sources and Notes:
[1]: Schedule No. BV-11; Panel A, [9] - [10].
[2]: Schedule No. BV-11; Panel B, [9] - [10].
[3]: Provided by Portland General Electric.
[4]: Based on a BBB rating. Yield from Bloomberg as of March 31, 2021.
[5]: Provided by Portland General Electric.
[6]: Provided by Portland General Electric.
[7]: {[1] - ([3] x [4] x (1 - [5])}/ [6]
[8]: {[2] - ([3] x [4] x (1 - [5]))}/ [6]

Scenario 1: Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%.
Scenario 2: Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%.

Schedule No. BV-13

Hamada Adjustment to Obtain Unlevered Asset Beta

Company		Value Line Betas	Debt Beta	5-Year Average Common Equity to Market Value Ratio	5-Year Average Preferred Equity to Market Value Ratio	5-Year Average Debt to Market Value Ratio	Portland General Electric's Representative Income Tax Rate	Asset Beta: Without Taxes	Asset Beta: With Taxes
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Amer. States Water	*	0.65	0.05	0.82	0.00	0.18	27.0%	0.54	0.57
Amer. Water Works	*	0.85	0.05	0.66	0.00	0.34	27.0%	0.58	0.63
Artesian Res Corp	*	0.75	0.05	0.70	0.00	0.30	27.0%	0.54	0.58
Atmos Energy	*	0.80	0.05	0.71	0.00	0.29	27.0%	0.58	0.63
California Water	*	0.65	0.05	0.70	0.00	0.30	27.0%	0.47	0.51
Chesapeake Utilities	*	0.80	0.05	0.72	0.00	0.28	27.0%	0.59	0.63
Essential Utilities	*	0.95	0.05	0.73	0.00	0.27	27.0%	0.70	0.76
Global Water Resources Inc	*	0.75	0.05	0.66	0.00	0.34	27.0%	0.51	0.56
Middlesex Water	*	0.70	0.05	0.80	0.00	0.19	27.0%	0.57	0.60
New Jersey Resources	*	0.95	0.05	0.70	0.00	0.30	27.0%	0.68	0.73
NiSource Inc.	*	0.85	0.10	0.46	0.03	0.51	27.0%	0.45	0.50
Northwest Natural	*	0.80	0.10	0.65	0.00	0.35	27.0%	0.55	0.60
ONE Gas Inc.	*	0.80	0.05	0.71	0.00	0.29	27.0%	0.58	0.62
SJW Group	*	0.85	0.05	0.65	0.00	0.35	27.0%	0.57	0.62
South Jersey Inds.	*	1.05	0.10	0.52	0.00	0.48	27.0%	0.60	0.67
Southwest Gas	*	0.95	0.10	0.63	0.00	0.37	27.0%	0.63	0.69
Spire Inc.	*	0.85	0.05	0.55	0.01	0.44	27.0%	0.49	0.55
York Water Co. (The)	*	0.80	0.05	0.82	0.00	0.18	27.0%	0.66	0.70
Combined Sample Average		0.82	0.06	0.68	0.00	0.32	0.27	0.57	0.62
Gas Sample Average		0.87	0.07	0.63	0.00	0.37	0.27	0.57	0.63
Water Sample Average		0.77	0.05	0.73	0.00	0.27	0.27	0.57	0.61

Sources and Notes:
[1]: Workpaper # 1 to Schedule No. BV-10, [1].
[2]: Workpaper #1 to Schedule No. BV-13, [7].
[3]: Schedule No. BV-4, [4].
[4]: Schedule No. BV-4, [5].
[5]: Schedule No. BV-4, [6].
[6]: Portland General Electric's Representative Tax Rate.
[7]: [1]*[3] + [2]*([4] + [5]).
[8]: {[1]*[3] + [2]*([4]+[5]*(1-[6]))} / {[3] + [4] + [5]*(1 -[6])}.

Schedule No. BV-14

Sample Average Asset Beta Relevered at Portland General Electric's Proposed Capital Structure

	Asset Beta	Assumed Debt Beta	Portland General Electric's Representative Regulatory % Debt	Portland General Electric's Representative Income Tax Rate	Portland General Electric's Representative Regulatory % Equity	Estimated Equity Beta
	[1]	[2]	[3]	[4]	[5]	[6]
Combined Sample						
Asset Beta Without Taxes	0.57	0.10	50.0%	27.0%	50.0%	1.04
Asset Beta With Taxes	0.62	0.10	50.0%	27.0%	50.0%	1.00
Water Sample						
Asset Beta Without Taxes	0.57	0.10	50.0%	27.0%	50.0%	1.05
Asset Beta With Taxes	0.61	0.10	50.0%	27.0%	50.0%	0.99
Gas Sample						
Asset Beta Without Taxes	0.57	0.10	50.0%	27.0%	50.0%	1.04
Asset Beta With Taxes	0.63	0.10	50.0%	27.0%	50.0%	1.01

Sources and Notes:
[1]: Schedule No. BV-13, [7] - [8].
[2]: Villadsen Testimony.
[3]: Provided by Portland General Electric.
[4]: Portland General Electric's Representative Tax Rate.
[5]: Provided by Portland General Electric.
[6]: [1] + [3]/[5]*([1] - [2]) without taxes, [1] + [3]*(1 - [4])/[5]*([1] - [2]) with taxes.

Schedule No. BV-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel A: Scenario 1 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%

Company	Long-Term Risk-Free Rate	Hamada Adjusted Equity Betas	Long-Term Market Risk	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Combined Sample					
Asset Beta Without Taxes	2.80%	1.04	7.25%	10.4%	10.3%
Asset Beta With Taxes	2.80%	1.00	7.25%	10.0%	10.0%
Water Sample					
Asset Beta Without Taxes	2.80%	1.05	7.25%	10.4%	10.3%
Asset Beta With Taxes	2.80%	0.99	7.25%	10.0%	10.0%
Gas Sample					
Asset Beta Without Taxes	2.80%	1.04	7.25%	10.4%	10.3%
Asset Beta With Taxes	2.80%	1.01	7.25%	10.1%	10.1%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Schedule No. BV-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel B: Scenario 2 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%

Company	Long-Term Risk-Free Rate	Hamada Adjusted Equity Betas	Long-Term Market Risk	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Combined Sample					
Asset Beta Without Taxes	2.80%	1.04	8.00%	11.2%	11.1%
Asset Beta With Taxes	2.80%	1.00	8.00%	10.8%	10.8%
Water Sample					
Asset Beta Without Taxes	2.80%	1.05	8.00%	11.2%	11.1%
Asset Beta With Taxes	2.80%	0.99	8.00%	10.7%	10.7%
Gas Sample					
Asset Beta Without Taxes	2.80%	1.04	8.00%	11.1%	11.1%
Asset Beta With Taxes	2.80%	1.01	8.00%	10.9%	10.9%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Schedule No. BV-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-2

Sample

Classification of Companies by Assets

Company	Company Category
Amer. States Water	R
Amer. Water Works	R
Artesian Res Corp	R
Atmos Energy	R
California Water	R
Chesapeake Utilities	R
Essential Utilities	R
Global Water Resources Inc	R
Middlesex Water	R
New Jersey Resources	MR
NiSource Inc.	R
Northwest Natural	R
ONE Gas Inc.	R
SJW Group	R
South Jersey Inds.	R
Southwest Gas	R
Spire Inc.	R
York Water Co. (The)	R

Sources and Notes:
Calculations based on EEI definitions and Company 10K filings:
R = Regulated (greater than 80 percent of total assets are regulated).
MR = Mostly Regulated (Less than 80 percent of total assets are regulated).

Schedule No. BV-3

Market Value of the Sample

Panel A: Amer. States Water

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$642	$642	$602	$558	$530	$494	$466	[a]
Shares Outstanding (in millions) - Common	37	37	37	37	37	37	37	[b]
Price per Share - Common	$74	$78	$87	$67	$56	$45	$42	[c]
Market Value of Common Equity	$2,722	$2,874	$3,189	$2,466	$2,055	$1,662	$1,533	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$2,722	$2,874	$3,189	$2,466	$2,055	$1,662	$1,533	[f]= [d] + [e]
Market to Book Value of Common Equity	4.24	4.48	5.30	4.42	3.88	3.36	3.29	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$157	$157	$122	$131	$155	$167	$133	[j]
Current Liabilities	$119	$119	$116	$147	$157	$178	$124	[k]
Current Portion of Long-Term Debt	$2	$2	$2	$40	$0	$0	$0	[l]
Net Working Capital	$41	$41	$9	$25	($1)	($11)	$10	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$5	$0	$59	$90	$28	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$1	$11	$0	[o] = See Sources and Notes.
Long-Term Debt	$584	$584	$493	$377	$321	$321	$321	[p]
Book Value of Long-Term Debt	$587	$587	$495	$417	$322	$332	$321	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$560	$560	$376	$388	$424	$424	$404	
Carrying Amount	$444	$444	$285	$325	$325	$326	$326	
Adjustment to Book Value of Long-Term Debt	$115	$115	$91	$63	$99	$98	$78	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$702	$702	$586	$480	$421	$430	$399	[s] = [q] + [r].
Market Value of Debt	$702	$702	$586	$480	$421	$430	$399	[t] = [s].
MARKET VALUE OF FIRM	$3,424	$3,576	$3,775	$2,946	$2,476	$2,091	$1,933	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	79.50%	80.37%	84.48%	83.71%	83.00%	79.44%	79.34%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	20.50%	19.63%	15.52%	16.29%	17.00%	20.56%	20.66%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel B: Amer. Water Works

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$6,454	$6,454	$6,121	$5,864	$5,385	$5,218	$5,049	[a]
Shares Outstanding (in millions) - Common	181	181	181	181	178	178	178	[b]
Price per Share - Common	$143	$150	$121	$93	$91	$73	$59	[c]
Market Value of Common Equity	$25,862	$27,177	$21,963	$16,789	$16,150	$12,972	$10,497	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$25,862	$27,177	$21,963	$16,789	$16,150	$12,972	$10,497	[f]= [d] + [e]
Market to Book Value of Common Equity	4.01	4.21	3.59	2.86	3.00	2.49	2.08	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,906	$1,906	$1,285	$781	$720	$784	$657	[j]
Current Liabilities	$2,881	$2,881	$2,045	$2,094	$2,325	$2,392	$1,533	[k]
Current Portion of Long-Term Debt	$342	$342	$42	$71	$322	$574	$54	[l]
Net Working Capital	($633)	($633)	($718)	($1,242)	($1,283)	($1,034)	($822)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,282	$1,282	$786	$964	$905	$849	$628	[n]
Adjusted Short-Term Debt	$633	$633	$718	$964	$905	$849	$628	[o] = See Sources and Notes.
Long-Term Debt	$9,414	$9,414	$8,733	$7,576	$6,498	$5,760	$5,874	[p]
Book Value of Long-Term Debt	$10,389	$10,389	$9,493	$8,611	$7,725	$7,183	$6,556	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$11,807	$11,807	$9,770	$7,921	$7,643	$7,044	$6,757	
Carrying Amount	$9,656	$9,656	$8,664	$7,638	$6,809	$6,320	$5,914	
Adjustment to Book Value of Long-Term Debt	$2,151	$2,151	$1,106	$283	$834	$724	$843	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$12,540	$12,540	$10,599	$8,894	$8,559	$7,907	$7,399	[s] = [q] + [r].
Market Value of Debt	$12,540	$12,540	$10,599	$8,894	$8,559	$7,907	$7,399	[t] = [s].
MARKET VALUE OF FIRM	$38,402	$39,717	$32,562	$25,683	$24,709	$20,879	$17,896	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	67.35%	68.43%	67.45%	65.37%	65.36%	62.13%	58.65%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	32.65%	31.57%	32.55%	34.63%	34.64%	37.87%	41.35%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel C: Artesian Res Corp

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$169	$169	$160	$153	$147	$139	$132	[a]
Shares Outstanding (in millions) - Common	9	9	9	9	9	9	9	[b]
Price per Share - Common	$40	$38	$37	$36	$38	$32	$27	[c]
Market Value of Common Equity	$376	$354	$346	$329	$353	$294	$245	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$376	$354	$346	$329	$353	$294	$245	[f]= [d] + [e]
Market to Book Value of Common Equity	2.22	2.09	2.16	2.15	2.41	2.11	1.85	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$18	$18	$14	$16	$19	$15	$14	[j]
Current Liabilities	$44	$44	$26	$38	$28	$19	$22	[k]
Current Portion of Long-Term Debt	$2	$2	$2	$2	$1	$1	$1	[l]
Net Working Capital	($24)	($24)	($10)	($20)	($8)	($3)	($7)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$27	$27	$8	$16	$10	$7	$11	[n]
Adjusted Short-Term Debt	$24	$24	$8	$16	$8	$3	$7	[o] = See Sources and Notes.
Long-Term Debt	$143	$143	$145	$116	$106	$102	$104	[p]
Book Value of Long-Term Debt	$169	$169	$154	$134	$115	$107	$112	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$171	$171	$158	$117	$111	$112	$120	
Carrying Amount	$144	$144	$146	$118	$107	$104	$105	
Adjustment to Book Value of Long-Term Debt	$27	$27	$12	($1)	$4	$8	$15	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$196	$196	$166	$133	$119	$115	$127	[s] = [q] + [r].
Market Value of Debt	$196	$196	$166	$133	$119	$115	$127	[t] = [s].
MARKET VALUE OF FIRM	$572	$550	$511	$462	$471	$409	$372	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	65.70%	64.34%	67.60%	71.21%	74.83%	71.83%	65.85%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	34.30%	35.66%	32.40%	28.79%	25.17%	28.17%	34.15%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel D: Atmos Energy

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$7,213	$7,213	$6,128	$5,348	$4,564	$3,699	$3,272	[a]
Shares Outstanding (in millions) - Common	128	128	122	117	111	105	102	[b]
Price per Share - Common	$95	$96	$109	$95	$88	$74	$63	[c]
Market Value of Common Equity	$12,156	$12,274	$13,387	$11,090	$9,729	$7,778	$6,398	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$12,156	$12,274	$13,387	$11,090	$9,729	$7,778	$6,398	[f]= [d] + [e]
Market to Book Value of Common Equity	1.69	1.70	2.18	2.07	2.13	2.10	1.96	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,192	$1,192	$812	$913	$779	$979	$863	[j]
Current Liabilities	$798	$798	$845	$1,455	$959	$1,950	$1,515	[k]
Current Portion of Long-Term Debt	$0	$0	$30	$575	$0	$250	$0	[l]
Net Working Capital	$395	$395	($3)	$32	($181)	($720)	($652)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$0	$337	$941	$763	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$181	$720	$652	[o] = See Sources and Notes.
Long-Term Debt	$5,125	$5,125	$4,528	$3,085	$3,067	$2,314	$2,455	[p]
Book Value of Long-Term Debt	$5,125	$5,125	$4,558	$3,660	$3,248	$3,285	$3,107	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$6,295	$6,295	$4,216	$3,162	$3,382	$2,845	$2,669	
Carrying Amount	$5,160	$5,160	$3,560	$3,085	$3,085	$2,460	$2,460	
Adjustment to Book Value of Long-Term Debt	$1,135	$1,135	$656	$77	$297	$385	$209	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$6,260	$6,260	$5,214	$3,736	$3,545	$3,670	$3,317	[s] = [q] + [r].
Market Value of Debt	$6,260	$6,260	$5,214	$3,736	$3,545	$3,670	$3,317	[t] = [s].
MARKET VALUE OF FIRM	$18,416	$18,534	$18,602	$14,827	$13,274	$11,448	$9,715	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	66.01%	66.23%	71.97%	74.80%	73.29%	67.95%	65.86%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	33.99%	33.77%	28.03%	25.20%	26.71%	32.05%	34.14%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel E: California Water

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$921	$921	$780	$730	$699	$659	$642	[a]
Shares Outstanding (in millions) - Common	50	50	49	48	48	48	48	[b]
Price per Share - Common	$55	$53	$51	$47	$44	$34	$23	[c]
Market Value of Common Equity	$2,747	$2,672	$2,472	$2,266	$2,097	$1,641	$1,116	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$2,747	$2,672	$2,472	$2,266	$2,097	$1,641	$1,116	[f]= [d] + [e]
Market to Book Value of Common Equity	2.98	2.90	3.17	3.10	3.00	2.49	1.74	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$266	$266	$185	$189	$228	$142	$128	[j]
Current Liabilities	$589	$589	$359	$321	$491	$250	$148	[k]
Current Portion of Long-Term Debt	$7	$7	$23	$105	$16	$26	$6	[l]
Net Working Capital	($316)	($316)	($151)	($28)	($247)	($82)	($14)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$370	$370	$175	$65	$275	$97	$34	[n]
Adjusted Short-Term Debt	$316	$316	$151	$28	$247	$82	$14	[o] = See Sources and Notes.
Long-Term Debt	$795	$795	$800	$710	$516	$532	$508	[p]
Book Value of Long-Term Debt	$1,118	$1,118	$974	$842	$779	$640	$528	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$944	$944	$873	$850	$607	$631	$600	
Carrying Amount	$786	$786	$809	$815	$532	$558	$519	
Adjustment to Book Value of Long-Term Debt	$158	$158	$64	$35	$76	$73	$82	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,276	$1,276	$1,038	$877	$855	$712	$610	[s] = [q] + [r].
Market Value of Debt	$1,276	$1,276	$1,038	$877	$855	$712	$610	[t] = [s].
MARKET VALUE OF FIRM	$4,022	$3,948	$3,509	$3,143	$2,952	$2,353	$1,725	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	68.28%	67.68%	70.43%	72.09%	71.05%	69.73%	64.65%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	31.72%	32.32%	29.57%	27.91%	28.95%	30.27%	35.35%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel F: Chesapeake Utilities

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$697	$697	$562	$518	$486	$446	$358	[a]
Shares Outstanding (in millions) - Common	17	17	16	16	16	16	15	[b]
Price per Share - Common	$117	$107	$96	$86	$79	$68	$56	[c]
Market Value of Common Equity	$2,049	$1,869	$1,569	$1,403	$1,293	$1,104	$851	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$2,049	$1,869	$1,569	$1,403	$1,293	$1,104	$851	[f]= [d] + [e]
Market to Book Value of Common Equity	2.94	2.68	2.79	2.71	2.66	2.48	2.38	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$136	$136	$135	$192	$179	$141	$112	[j]
Current Liabilities	$329	$329	$423	$528	$413	$334	$280	[k]
Current Portion of Long-Term Debt	$15	$15	$47	$12	$9	$12	$9	[l]
Net Working Capital	($177)	($177)	($241)	($325)	($225)	($181)	($159)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$176	$176	$247	$294	$251	$210	$173	[n]
Adjusted Short-Term Debt	$176	$176	$241	$294	$225	$181	$159	[o] = See Sources and Notes.
Long-Term Debt	$518	$518	$450	$316	$197	$137	$149	[p]
Book Value of Long-Term Debt	$709	$709	$739	$622	$432	$330	$317	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$549	$549	$505	$324	$215	$162	$165	
Carrying Amount	$523	$523	$487	$327	$205	$146	$154	
Adjustment to Book Value of Long-Term Debt	$26	$26	$18	($3)	$10	$16	$11	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$735	$735	$757	$619	$442	$345	$328	[s] = [q] + [r].
Market Value of Debt	$735	$735	$757	$619	$442	$345	$328	[t] = [s].
MARKET VALUE OF FIRM	$2,784	$2,604	$2,326	$2,022	$1,735	$1,450	$1,180	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	73.60%	71.78%	67.45%	69.38%	74.53%	76.17%	72.17%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	26.40%	28.22%	32.55%	30.62%	25.47%	23.83%	27.83%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel G: Essential Utilities

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$4,684	$4,684	$3,881	$2,009	$1,958	$1,850	$1,726	[a]
Shares Outstanding (in millions) - Common	245	245	221	178	178	177	177	[b]
Price per Share - Common	$44	$47	$46	$34	$38	$30	$30	[c]
Market Value of Common Equity	$10,681	$11,431	$10,168	$6,127	$6,795	$5,345	$5,248	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$10,681	$11,431	$10,168	$6,127	$6,795	$5,345	$5,248	[f]= [d] + [e]
Market to Book Value of Common Equity	2.28	2.44	2.62	3.05	3.47	2.89	3.04	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$380	$380	$2,015	$147	$131	$129	$128	[j]
Current Liabilities	$604	$604	$323	$399	$284	$302	$193	[k]
Current Portion of Long-Term Debt	$92	$92	$106	$145	$114	$151	$36	[l]
Net Working Capital	($132)	($132)	$1,798	($107)	($39)	($22)	($29)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$122	$122	$37	$24	$25	$7	$17	[n]
Adjusted Short-Term Debt	$122	$122	$0	$24	$25	$7	$17	[o] = See Sources and Notes.
Long-Term Debt	$5,563	$5,563	$2,955	$2,398	$2,008	$1,738	$1,720	[p]
Book Value of Long-Term Debt	$5,778	$5,778	$3,061	$2,567	$2,147	$1,895	$1,773	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$0	$0	$0	$0	$0	$0	$0	
Carrying Amount	$0	$0	$0	$0	$0	$0	$0	
Adjustment to Book Value of Long-Term Debt	$0	$0	$0	$0	$0	$0	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$5,778	$5,778	$3,061	$2,567	$2,147	$1,895	$1,773	[s] = [q] + [r].
Market Value of Debt	$5,778	$5,778	$3,061	$2,567	$2,147	$1,895	$1,773	[t] = [s].
MARKET VALUE OF FIRM	$16,459	$17,209	$13,229	$8,694	$8,942	$7,240	$7,021	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	64.90%	66.43%	76.86%	70.47%	75.99%	73.83%	74.75%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	35.10%	33.57%	23.14%	29.53%	24.01%	26.17%	25.25%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel H: Global Water Resources Inc

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$32	$32	$25	$28	$15	$15	$20	[a]
Shares Outstanding (in millions) - Common	23	23	22	22	20	20	18	[b]
Price per Share - Common	$17	$15	$13	$10	$9	$9	N/A	[c]
Market Value of Common Equity	$383	$334	$279	$218	$182	$174	N/A	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$383	$334	$279	$218	$182	$174	N/A	[f]= [d] + [e]
Market to Book Value of Common Equity	11.91	10.39	11.31	7.81	12.26	11.60	N/A	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$23	$23	$12	$17	$10	$25	$19	[j]
Current Liabilities	$12	$12	$10	$10	$9	$11	$11	[k]
Current Portion of Long-Term Debt	$2	$2	$0	$0	$0	$0	$2	[l]
Net Working Capital	$13	$13	$2	$8	$1	$14	$10	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$0	$0	$0	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$113	$113	$115	$115	$114	$114	$102	[p]
Book Value of Long-Term Debt	$115	$115	$115	$115	$114	$114	$104	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$128	$128	$121	$108	$116	$108	$117	
Carrying Amount	$113	$113	$115	$115	$114	$115	$105	
Adjustment to Book Value of Long-Term Debt	$15	$15	$6	($7)	$1	($7)	$12	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$130	$130	$121	$108	$116	$108	$116	[s] = [q] + [r].
Market Value of Debt	$130	$130	$121	$108	$116	$108	$116	[t] = [s].
MARKET VALUE OF FIRM	$513	$464	$400	$326	$298	$282	N/A	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	74.72%	72.04%	69.70%	66.86%	61.14%	61.74%	N/A	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	N/A	[w] = [i] / [u].
Debt - Market Value Ratio	25.28%	27.96%	30.30%	33.14%	38.86%	38.26%	N/A	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel I: Middlesex Water

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$346	$346	$324	$249	$229	$218	$207	[a]
Shares Outstanding (in millions) - Common	17	17	17	16	16	16	16	[b]
Price per Share - Common	$78	$72	$63	$53	$41	$42	$26	[c]
Market Value of Common Equity	$1,366	$1,264	$1,104	$876	$670	$691	$428	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$1,366	$1,264	$1,104	$876	$670	$691	$428	[f]= [d] + [e]
Market to Book Value of Common Equity	3.95	3.65	3.41	3.52	2.92	3.16	2.07	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$2	$2	$2	$2	$2	$2	$2	[h]
Market Value of Preferred Equity	$2	$2	$2	$2	$2	$2	$2	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$34	$34	$29	$31	$29	$27	$24	[j]
Current Liabilities	$57	$57	$65	$94	$65	$47	$28	[k]
Current Portion of Long-Term Debt	$8	$8	$8	$7	$7	$6	$6	[l]
Net Working Capital	($15)	($15)	($28)	($56)	($28)	($14)	$2	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$2	$2	$20	$49	$28	$12	$3	[n]
Adjusted Short-Term Debt	$2	$2	$20	$49	$28	$12	$0	[o] = See Sources and Notes.
Long-Term Debt	$278	$278	$237	$153	$139	$135	$133	[p]
Book Value of Long-Term Debt	$288	$288	$264	$209	$174	$153	$139	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$159	$159	$161	$103	$98	$85	$88	
Carrying Amount	$148	$148	$151	$101	$95	$83	$86	
Adjustment to Book Value of Long-Term Debt	$12	$12	$10	$1	$3	$2	$3	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$300	$300	$274	$210	$177	$155	$141	[s] = [q] + [r].
Market Value of Debt	$300	$300	$274	$210	$177	$155	$141	[t] = [s].
MARKET VALUE OF FIRM	$1,668	$1,566	$1,380	$1,089	$849	$848	$571	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	81.90%	80.72%	79.97%	80.48%	78.91%	81.47%	74.82%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.12%	0.13%	0.15%	0.22%	0.29%	0.29%	0.43%	[w] = [i] / [u].
Debt - Market Value Ratio	17.97%	19.15%	19.88%	19.29%	20.80%	18.25%	24.76%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel J: New Jersey Resources

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$1,698	$1,698	$1,828	$1,497	$1,348	$1,185	$1,144	[a]
Shares Outstanding (in millions) - Common	96	96	90	89	87	86	86	[b]
Price per Share - Common	$41	$35	$44	$48	$40	$36	$31	[c]
Market Value of Common Equity	$3,902	$3,338	$3,977	$4,241	$3,536	$3,119	$2,663	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,902	$3,338	$3,977	$4,241	$3,536	$3,119	$2,663	[f]= [d] + [e]
Market to Book Value of Common Equity	2.30	1.97	2.18	2.83	2.62	2.63	2.33	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$609	$609	$693	$1,050	$826	$815	$589	[j]
Current Liabilities	$519	$519	$806	$999	$991	$823	$575	[k]
Current Portion of Long-Term Debt	$31	$31	$26	$125	$166	$97	$11	[l]
Net Working Capital	$122	$122	($87)	$176	$1	$89	$25	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$134	$134	$391	$372	$373	$285	$211	[n]
Adjusted Short-Term Debt	$0	$0	$87	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$2,370	$2,370	$1,657	$1,185	$1,001	$1,027	$848	[p]
Book Value of Long-Term Debt	$2,401	$2,401	$1,770	$1,310	$1,167	$1,124	$859	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,455	$2,455	$984	$669	$673	$732	$584	
Carrying Amount	$2,103	$2,103	$893	$672	$672	$708	$583	
Adjustment to Book Value of Long-Term Debt	$352	$352	$91	($3)	$1	$24	$1	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,754	$2,754	$1,861	$1,307	$1,168	$1,147	$861	[s] = [q] + [r].
Market Value of Debt	$2,754	$2,754	$1,861	$1,307	$1,168	$1,147	$861	[t] = [s].
MARKET VALUE OF FIRM	$6,656	$6,091	$5,838	$5,548	$4,705	$4,266	$3,524	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.63%	54.79%	68.12%	76.45%	75.17%	73.11%	75.58%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	41.37%	45.21%	31.88%	23.55%	24.83%	26.89%	24.42%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel K: NiSource Inc.

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$4,872	$4,872	$5,107	$4,871	$4,320	$4,071	$3,844	[a]
Shares Outstanding (in millions) - Common	392	392	382	372	337	323	319	[b]
Price per Share - Common	$24	$22	$27	$26	$26	$22	$19	[c]
Market Value of Common Equity	$9,224	$8,793	$10,437	$9,805	$8,714	$7,144	$6,128	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$9,224	$8,793	$10,437	$9,805	$8,714	$7,144	$6,128	[f]= [d] + [e]
Market to Book Value of Common Equity	1.89	1.80	2.04	2.01	2.02	1.75	1.59	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$880	$880	$880	$880	$0	$0	$0	[h]
Market Value of Preferred Equity	$880	$880	$880	$880	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,659	$1,659	$1,854	$2,055	$1,763	$1,762	$1,577	[j]
Current Liabilities	$2,279	$2,279	$3,746	$4,037	$3,178	$3,452	$2,658	[k]
Current Portion of Long-Term Debt	$34	$34	$27	$50	$284	$363	$434	[l]
Net Working Capital	($586)	($586)	($1,865)	($1,931)	($1,131)	($1,327)	($647)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$503	$503	$1,773	$1,977	$1,206	$1,488	$567	[n]
Adjusted Short-Term Debt	$503	$503	$1,773	$1,931	$1,131	$1,327	$567	[o] = See Sources and Notes.
Long-Term Debt	$9,250	$9,250	$7,908	$7,313	$7,675	$6,058	$5,949	[p]
Book Value of Long-Term Debt	$9,786	$9,786	$9,708	$9,295	$9,090	$7,748	$6,950	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$11,034	$11,034	$8,764	$7,228	$8,603	$7,064	$6,976	
Carrying Amount	$9,243	$9,243	$7,870	$7,155	$7,797	$6,421	$6,382	
Adjustment to Book Value of Long-Term Debt	$1,791	$1,791	$895	$73	$807	$643	$594	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$11,577	$11,577	$10,602	$9,368	$9,897	$8,391	$7,543	[s] = [q] + [r].
Market Value of Debt	$11,577	$11,577	$10,602	$9,368	$9,897	$8,391	$7,543	[t] = [s].
MARKET VALUE OF FIRM								
	$21,681	$21,251	$21,919	$20,053	$18,611	$15,536	$13,671	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	42.54%	41.38%	47.61%	48.90%	46.82%	45.99%	44.82%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	4.06%	4.14%	4.01%	4.39%	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	53.40%	54.48%	48.37%	46.71%	53.18%	54.01%	55.18%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel L: Northwest Natural

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$889	$889	$866	$763	$743	$850	$781	[a]
Shares Outstanding (in millions) - Common	31	31	30	29	29	29	27	[b]
Price per Share - Common	$53	$48	$72	$63	$62	$60	$50	[c]
Market Value of Common Equity	$1,609	$1,459	$2,184	$1,832	$1,771	$1,726	$1,369	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$1,609	$1,459	$2,184	$1,832	$1,771	$1,726	$1,369	[f]= [d] + [e]
Market to Book Value of Common Equity	1.81	1.64	2.52	2.40	2.38	2.03	1.75	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$323	$323	$294	$296	$270	$288	$331	[j]
Current Liabilities	$627	$627	$482	$509	$382	$275	$478	[k]
Current Portion of Long-Term Debt	$96	$96	$77	$30	$97	$40	$25	[l]
Net Working Capital	($207)	($207)	($111)	($183)	($15)	$54	($122)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$305	$305	$149	$218	$54	$53	$270	[n]
Adjusted Short-Term Debt	$207	$207	$111	$183	$15	$0	$122	[o] = See Sources and Notes.
Long-Term Debt	$941	$941	$807	$706	$683	$679	$569	[p]
Book Value of Long-Term Debt	$1,245	$1,245	$995	$919	$795	$719	$716	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$920	$920	$920	$760	$853	$793	$667	
Carrying Amount	$917	$917	$844	$734	$780	$719	$602	
Adjustment to Book Value of Long-Term Debt	$3	$3	$76	$26	$73	$74	$65	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,247	$1,247	$1,071	$946	$869	$793	$782	[s] = [q] + [r].
Market Value of Debt	$1,247	$1,247	$1,071	$946	$869	$793	$782	[t] = [s].
MARKET VALUE OF FIRM	$2,856	$2,706	$3,256	$2,778	$2,640	$2,519	$2,151	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.34%	53.91%	67.10%	65.96%	67.09%	68.51%	63.65%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	43.66%	46.09%	32.90%	34.04%	32.91%	31.49%	36.35%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel M: ONE Gas Inc.

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$2,233	$2,233	$2,129	$2,043	$1,960	$1,888	$1,842	[a]
Shares Outstanding (in millions) - Common	53	53	53	53	52	52	52	[b]
Price per Share - Common	$75	$78	$92	$83	$75	$64	$49	[c]
Market Value of Common Equity	$3,998	$4,150	$4,876	$4,340	$3,904	$3,324	$2,577	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,998	$4,150	$4,876	$4,340	$3,904	$3,324	$2,577	[f]= [d] + [e]
Market to Book Value of Common Equity	1.79	1.86	2.29	2.12	1.99	1.76	1.40	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$540	$540	$506	$543	$589	$569	$483	[j]
Current Liabilities	$797	$797	$873	$699	$1,193	$444	$304	[k]
Current Portion of Long-Term Debt	$7	$7	$7	$300	$0	$0	$0	[l]
Net Working Capital	($250)	($250)	($360)	$144	($604)	$125	$179	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$418	$418	$517	$300	$357	$145	$13	[n]
Adjusted Short-Term Debt	$250	$250	$360	$0	$357	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,613	$1,613	$1,314	$1,285	$1,193	$1,192	$1,192	[p]
Book Value of Long-Term Debt	$1,870	$1,870	$1,681	$1,585	$1,550	$1,192	$1,192	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,000	$2,000	$1,500	$1,400	$1,300	$1,200	$1,200	
Carrying Amount	$1,600	$1,600	$1,286	$1,300	$1,200	$1,200	$1,200	
Adjustment to Book Value of Long-Term Debt	$400	$400	$214	$100	$100	$0	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,270	$2,270	$1,894	$1,685	$1,650	$1,192	$1,192	[s] = [q] + [r].
Market Value of Debt	$2,270	$2,270	$1,894	$1,685	$1,650	$1,192	$1,192	[t] = [s].
MARKET VALUE OF FIRM	$6,269	$6,420	$6,771	$6,025	$5,555	$4,517	$3,768	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	63.78%	64.64%	72.02%	72.03%	70.29%	73.60%	68.38%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	36.22%	35.36%	27.98%	27.97%	29.71%	26.40%	31.62%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel N: SJW Group

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$917	$917	$890	$889	$463	$422	$384	[a]
Shares Outstanding (in millions) - Common	29	29	28	28	21	20	20	[b]
Price per Share - Common	$61	$68	$71	$55	$64	$56	$30	[c]
Market Value of Common Equity	$1,739	$1,953	$2,013	$1,566	$1,304	$1,143	$602	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$1,739	$1,953	$2,013	$1,566	$1,304	$1,143	$602	[f]= [d] + [e]
Market to Book Value of Common Equity	1.90	2.13	2.26	1.76	2.81	2.71	1.57	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$127	$127	$122	$503	$67	$100	$73	[j]
Current Liabilities	$351	$351	$235	$164	$85	$64	$80	[k]
Current Portion of Long-Term Debt	$76	$76	$22	$0	$0	$0	$3	[l]
Net Working Capital	($147)	($147)	($90)	$339	($18)	$36	($3)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$175	$175	$117	$100	$25	$14	$35	[n]
Adjusted Short-Term Debt	$147	$147	$90	$0	$18	$0	$3	[o] = See Sources and Notes.
Long-Term Debt	$1,288	$1,288	$1,284	$431	$431	$433	$377	[p]
Book Value of Long-Term Debt	$1,511	$1,511	$1,396	$431	$449	$433	$383	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,571	$1,571	$1,396	$490	$538	$502	$500	
Carrying Amount	$1,288	$1,288	$1,284	$431	$431	$433	$381	
Adjustment to Book Value of Long-Term Debt	$283	$283	$112	$59	$107	$69	$119	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,794	$1,794	$1,509	$490	$556	$502	$503	[s] = [q] + [r].
Market Value of Debt	$1,794	$1,794	$1,509	$490	$556	$502	$503	[t] = [s].
MARKET VALUE OF FIRM	$3,534	$3,747	$3,521	$2,056	$1,860	$1,645	$1,105	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	49.23%	52.12%	57.16%	76.17%	70.09%	69.47%	54.51%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	50.77%	47.88%	42.84%	23.83%	29.91%	30.53%	45.49%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
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Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel O: South Jersey Inds.

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$1,661	$1,661	$1,424	$1,267	$1,192	$1,289	$1,038	[a]
Shares Outstanding (in millions) - Common	101	101	92	86	80	79	71	[b]
Price per Share - Common	$24	$22	$32	$29	$32	$34	$23	[c]
Market Value of Common Equity	$2,409	$2,232	$2,965	$2,473	$2,516	$2,719	$1,648	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$2,409	$2,232	$2,965	$2,473	$2,516	$2,719	$1,648	[f]= [d] + [e]
Market to Book Value of Common Equity	1.45	1.34	2.08	1.95	2.11	2.11	1.59	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$507	$507	$653	$663	$439	$473	$431	[j]
Current Liabilities	$1,164	$1,164	$1,732	$1,581	$883	$953	$832	[k]
Current Portion of Long-Term Debt	$143	$143	$469	$734	$64	$232	$29	[l]
Net Working Capital	($513)	($513)	($610)	($184)	($380)	($247)	($372)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$596	$596	$849	$271	$346	$296	$432	[n]
Adjusted Short-Term Debt	$513	$513	$610	$184	$346	$247	$372	[o] = See Sources and Notes.
Long-Term Debt	$2,778	$2,778	$2,071	$2,107	$1,123	$808	$997	[p]
Book Value of Long-Term Debt	$3,435	$3,435	$3,150	$3,025	$1,533	$1,287	$1,399	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,197	$1,197	$915	$895	$839	$1,081	$1,079	
Carrying Amount	$1,069	$1,069	$965	$893	$822	$1,047	$1,036	
Adjustment to Book Value of Long-Term Debt	$128	$128	($50)	$2	$17	$33	$43	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,562	$3,562	$3,100	$3,026	$1,550	$1,321	$1,442	[s] = [q] + [r].
Market Value of Debt	$3,562	$3,562	$3,100	$3,026	$1,550	$1,321	$1,442	[t] = [s].
MARKET VALUE OF FIRM	$5,971	$5,794	$6,065	$5,500	$4,066	$4,039	$3,090	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	40.34%	38.52%	48.88%	44.97%	61.88%	67.30%	53.34%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	59.66%	61.48%	51.12%	55.03%	38.12%	32.70%	46.66%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel P: Southwest Gas

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$2,675	$2,675	$2,506	$2,252	$1,815	$1,663	$1,594	[a]
Shares Outstanding (in millions) - Common	57	57	55	53	48	47	47	[b]
Price per Share - Common	$67	$61	$76	$79	$81	$76	$53	[c]
Market Value of Common Equity	$3,853	$3,516	$4,161	$4,200	$3,889	$3,606	$2,528	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,853	$3,516	$4,161	$4,200	$3,889	$3,606	$2,528	[f]= [d] + [e]
Market to Book Value of Common Equity	1.44	1.31	1.66	1.86	2.14	2.17	1.59	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$871	$871	$860	$840	$657	$533	$558	[j]
Current Liabilities	$912	$912	$1,080	$939	$816	$628	$535	[k]
Current Portion of Long-Term Debt	$51	$51	$187	$33	$25	$50	$19	[l]
Net Working Capital	$10	$10	($33)	($66)	($134)	($45)	$43	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$107	$107	$211	$152	$215	$0	$18	[n]
Adjusted Short-Term Debt	$0	$0	$33	$66	$134	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$2,810	$2,810	$2,375	$2,107	$1,799	$1,550	$1,551	[p]
Book Value of Long-Term Debt	$2,861	$2,861	$2,595	$2,206	$1,957	$1,600	$1,571	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,628	$2,628	$2,628	$2,173	$1,849	$1,600	$1,571	
Carrying Amount	$2,732	$2,732	$2,300	$2,107	$1,799	$1,550	$1,551	
Adjustment to Book Value of Long-Term Debt	($105)	($105)	$327	$66	$51	$50	$19	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,756	$2,756	$2,922	$2,272	$2,008	$1,650	$1,590	[s] = [q] + [r].
Market Value of Debt	$2,756	$2,756	$2,922	$2,272	$2,008	$1,650	$1,590	[t] = [s].
MARKET VALUE OF FIRM	$6,609	$6,272	$7,083	$6,472	$5,897	$5,256	$4,118	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.30%	56.06%	58.75%	64.89%	65.95%	68.60%	61.39%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	41.70%	43.94%	41.25%	35.11%	34.05%	31.40%	38.61%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel Q: Spire Inc.

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$2,345	$2,345	$2,344	$2,285	$2,079	$1,797	$1,600	[a]
Shares Outstanding (in millions) - Common	52	52	51	51	48	46	43	[b]
Price per Share - Common	$74	$64	$82	$76	$76	$64	$58	[c]
Market Value of Common Equity	$3,803	$3,323	$4,190	$3,859	$3,677	$2,935	$2,533	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$3,803	$3,323	$4,190	$3,859	$3,677	$2,935	$2,533	[f]= [d] + [e]
Market to Book Value of Common Equity	1.62	1.42	1.79	1.69	1.77	1.63	1.58	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$242	$242	$242	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$242	$242	$242	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$770	$770	$776	$905	$853	$816	$636	[j]
Current Liabilities	$1,547	$1,547	$1,253	$1,563	$1,211	$1,342	$848	[k]
Current Portion of Long-Term Debt	$111	$111	$45	$175	$106	$250	$0	[l]
Net Working Capital	($666)	($666)	($431)	($483)	($253)	($277)	($212)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$696	$696	$519	$626	$584	$506	$377	[n]
Adjusted Short-Term Debt	$666	$666	$431	$483	$253	$277	$212	[o] = See Sources and Notes.
Long-Term Debt	$2,518	$2,518	$2,484	$1,992	$2,030	$1,821	$1,852	[p]
Book Value of Long-Term Debt	$3,294	$3,294	$2,961	$2,650	$2,389	$2,348	$2,063	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$3,120	$3,120	$2,373	$2,074	$2,210	$2,257	$1,944	
Carrying Amount	$2,628	$2,628	$2,123	$2,076	$2,095	$2,084	$1,852	
Adjustment to Book Value of Long-Term Debt	$491	$491	$251	($2)	$115	$173	$93	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,785	$3,785	$3,211	$2,649	$2,504	$2,521	$2,156	[s] = [q] + [r].
Market Value of Debt	$3,785	$3,785	$3,211	$2,649	$2,504	$2,521	$2,156	[t] = [s].
MARKET VALUE OF FIRM	$7,830	$7,351	$7,643	$6,507	$6,181	$5,456	$4,688	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	48.56%	45.21%	54.82%	59.30%	59.49%	53.79%	54.02%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	3.09%	3.29%	3.17%	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	48.34%	51.50%	42.02%	40.70%	40.51%	46.21%	45.98%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-3

Market Value of the Sample

Panel R: York Water Co. (The)

($MM)

	DCF Capital Structure	Year End, 2020	Year End, 2019	Year End, 2018	Year End, 2017	Year End, 2016	Year End, 2015	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/20	12/31/19	12/31/18	12/31/17	12/31/16	12/31/15	
Book Value, Common Shareholder's Equity	$143	$143	$134	$126	$119	$114	$109	[a]
Shares Outstanding (in millions) - Common	13	13	13	13	13	13	13	[b]
Price per Share - Common	$49	$47	$46	$33	$34	$39	$25	[c]
Market Value of Common Equity	$634	$619	$597	$427	$441	$496	$318	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e] = See Sources and Notes.
Total Market Value of Equity	$634	$619	$597	$427	$441	$496	$318	[f]= [d] + [e]
Market to Book Value of Common Equity	4.42	4.32	4.45	3.38	3.70	4.35	2.92	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$16	$16	$9	$9	$9	$13	$12	[j]
Current Liabilities	$12	$12	$15	$11	$9	$8	$6	[k]
Current Portion of Long-Term Debt	$0	$0	$7	$0	$0	$0	$0	[l]
Net Working Capital	$4	$4	$1	($2)	($0)	$4	$5	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$1	$1	$0	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$1	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$124	$124	$95	$93	$90	$85	$85	[p]
Book Value of Long-Term Debt	$124	$124	$101	$94	$91	$85	$85	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$151	$151	$115	$105	$108	$99	$102	
Carrying Amount	$127	$127	$104	$96	$93	$87	$88	
Adjustment to Book Value of Long-Term Debt	$24	$24	$11	$9	$15	$12	$14	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$148	$148	$112	$103	$106	$96	$99	[s] = [q] + [r].
Market Value of Debt	$148	$148	$112	$103	$106	$96	$99	[t] = [s].
MARKET VALUE OF FIRM	$782	$767	$709	$531	$547	$592	$417	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	81.06%	80.70%	84.21%	80.50%	80.66%	83.75%	76.26%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	18.94%	19.30%	15.79%	19.50%	19.34%	16.25%	23.74%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of March 31, 2021
Capital structure from Year End, 2020 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2020 balance sheet information and a 15-trading day average closing price ending on 3/31/2021.
Prices are reported in Workpaper #1 to Schedule No. BV-6.
[e] = Market Value of GP equity is not estimated here.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2015 to 2019 10-Ks.

Schedule No. BV-4

Sample

Capital Structure Summary of the Sample

	DCF Capital Structure			5-Year Average Capital Structure		
Company	Common Equity - Value Ratio	Preferred Equity - Value Ratio	Debt - Value Ratio	Common Equity - Value Ratio	Preferred Equity - Value Ratio	Debt - Value Ratio
	[1]	[2]	[3]	[4]	[5]	[6]
Amer. States Water	0.79	0.00	0.21	0.82	0.00	0.18
Amer. Water Works	0.67	0.00	0.33	0.66	0.00	0.34
Artesian Res Corp	0.66	0.00	0.34	0.70	0.00	0.30
Atmos Energy	0.66	0.00	0.34	0.71	0.00	0.29
California Water	0.68	0.00	0.32	0.70	0.00	0.30
Chesapeake Utilities	0.74	0.00	0.26	0.72	0.00	0.28
Essential Utilities	0.65	0.00	0.35	0.73	0.00	0.27
Global Water Resources Inc	0.75	0.00	0.25	0.66	0.00	0.34
Middlesex Water	0.82	0.00	0.18	0.80	0.00	0.19
New Jersey Resources	0.59	0.00	0.41	0.70	0.00	0.30
NiSource Inc.	0.43	0.04	0.53	0.46	0.03	0.51
Northwest Natural	0.56	0.00	0.44	0.65	0.00	0.35
ONE Gas Inc.	0.64	0.00	0.36	0.71	0.00	0.29
SJW Group	0.49	0.00	0.51	0.65	0.00	0.35
South Jersey Inds.	0.40	0.00	0.60	0.52	0.00	0.48
Southwest Gas	0.58	0.00	0.42	0.63	0.00	0.37
Spire Inc.	0.49	0.03	0.48	0.55	0.01	0.44
York Water Co. (The)	0.81	0.00	0.19	0.82	0.00	0.18
Combined Sample Average	0.63	0.00	0.36	0.68	0.00	0.32
Water Sample Average	0.70	0.00	0.30	0.73	0.00	0.27
Gas Sample Average	0.56	0.01	0.43	0.63	0.00	0.37

Sources and Notes:
[1], [4]:Workpaper #1 to Schedule No. BV-4.
[2], [5]:Workpaper #2 to Schedule No. BV-4.
[3], [6]:Workpaper #3 to Schedule No. BV-4.
Values in this table may not add up exactly to 1.0 because of rounding.

Schedule No. BV-5

Sample

Estimated Growth Rates of the Sample

	Thomson Reuters IBES Estimate		Value Line			
Company	Long-Term Growth Rate	Number of Estimates	EPS Year 2020 Estimate	EPS Year 2023-2025 Estimate	Annualized Growth Rate	Combined Growth Rate
	[1]	[2]	[3]	[4]	[5]	[6]
Amer. States Water	4.6%	1	2.40	3.05	6.2%	5.4%
Amer. Water Works	8.6%	1	4.25	5.50	6.7%	7.6%
Artesian Res Corp	4.0%	1	n/a	n/a	n/a	4.0%
Atmos Energy	7.0%	3	5.00	6.50	6.8%	6.9%
California Water	10.8%	2	1.90	2.25	4.3%	8.6%
Chesapeake Utilities	4.7%	1	4.25	5.75	7.8%	6.3%
Essential Utilities	6.4%	1	1.65	1.90	3.6%	5.0%
Global Water Resources Inc	15.0%	1	n/a	n/a	n/a	15.0%
Middlesex Water	2.7%	1	2.25	2.70	4.7%	3.7%
New Jersey Resources	6.0%	1	1.65	2.45	10.4%	8.2%
NiSource Inc.	4.4%	1	1.40	2.30	13.2%	8.8%
Northwest Natural	3.1%	1	2.50	3.10	5.5%	4.3%
ONE Gas Inc.	5.0%	1	3.80	5.00	7.1%	6.1%
SJW Group	5.5%	1	2.55	3.65	9.4%	7.4%
South Jersey Inds.	4.4%	1	1.70	2.50	10.1%	7.3%
Southwest Gas	4.0%	1	4.45	6.50	9.9%	7.0%
Spire Inc.	5.7%	2	3.85	5.15	7.5%	6.3%
York Water Co. (The)	4.9%	1	1.35	1.65	5.1%	5.0%

Sources and Notes:
[1] - [2]: Thomson Reuters as of March 31, 2021.
[3] - [4]: From Valueline Investment Analyzer as of March 31, 2021.
[5]: ([4] / [3]) ^ (1/4) - 1.
[6]: ([1] x [2] + [5]) / ([2] + 1).
Weighted average growth rate. If information is missing from one source, the weighted average is based solely on the other source.

Schedule No. BV-6

DCF Cost of Equity of the Sample

Panel A: Simple DCF Method (Quarterly)

Company	Stock Price	Most Recent Dividend	Quarterly Dividend Yield	Combined Long-Term Growth Rate	Quarterly Growth Rate	DCF Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]
Amer. States Water	$73.79	$0.34	0.46%	5.4%	1.3%	7.3%
Amer. Water Works	$142.65	$0.55	0.39%	7.6%	1.9%	9.3%
Artesian Res Corp	$40.16	$0.26	0.65%	4.0%	1.0%	6.7%
Atmos Energy	$94.85	$0.63	0.67%	6.9%	1.7%	9.8%
California Water	$54.57	$0.23	0.43%	8.6%	2.1%	10.4%
Chesapeake Utilities	$117.33	$0.44	0.38%	6.3%	1.5%	7.9%
Essential Utilities	$43.53	$0.25	0.58%	5.0%	1.2%	7.4%
Global Water Resources Ir	$16.97	$0.02	0.15%	15.0%	3.6%	15.7%
Middlesex Water	$78.19	$0.27	0.35%	3.7%	0.9%	5.1%
New Jersey Resources	$40.59	$0.33	0.84%	8.2%	2.0%	11.8%
NiSource Inc.	$23.54	$0.22	0.95%	8.8%	2.1%	12.9%
Northwest Natural	$52.60	$0.48	0.92%	4.3%	1.1%	8.2%
ONE Gas Inc.	$75.20	$0.58	0.78%	6.1%	1.5%	9.4%
SJW Group	$60.91	$0.34	0.57%	7.4%	1.8%	9.9%
South Jersey Inds.	$23.95	$0.30	1.29%	7.3%	1.8%	12.8%
Southwest Gas	$67.37	$0.57	0.86%	7.0%	1.7%	10.6%
Spire Inc.	$73.61	$0.65	0.90%	6.3%	1.5%	10.1%
York Water Co. (The)	$48.51	$0.19	0.39%	5.0%	1.2%	6.7%

Sources and Notes:
[1]: Workpaper #1 to Schedule No. BV-6.
[2]: Workpaper #2 to Schedule No. BV-6.
[3]: ([2] / [1]) x (1 + [5]).
[4]: Schedule No. BV-5, [6].
[5]: {(1 + [4]) ^ (1/4)} - 1.
[6]: {([3] + [5] + 1) ^ 4} - 1.

Schedule No. BV-6

DCF Cost of Equity of the Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	Stock Price	Most Recent Dividend	Combined Long-Term Growth Rate	Growth Rate: Year 6	Growth Rate: Year 7	Growth Rate: Year 8	Growth Rate: Year 9	Growth Rate: Year 10	GDP Long-Term Growth Rate	DCF Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Amer. States Water	$73.79	$0.34	5.4%	5.1%	4.9%	4.6%	4.4%	4.1%	3.9%	6.0%
Amer. Water Works	$142.65	$0.55	7.6%	7.0%	6.4%	5.8%	5.1%	4.5%	3.9%	6.0%
Artesian Res Corp	$40.16	$0.26	4.0%	4.0%	4.0%	4.0%	3.9%	3.9%	3.9%	6.6%
Atmos Energy	$94.85	$0.63	6.9%	6.4%	5.9%	5.4%	4.9%	4.4%	3.9%	7.3%
California Water	$54.57	$0.23	8.6%	7.8%	7.0%	6.3%	5.5%	4.7%	3.9%	6.3%
Chesapeake Utilities	$117.33	$0.44	6.3%	5.9%	5.5%	5.1%	4.7%	4.3%	3.9%	5.7%
Essential Utilities	$43.53	$0.25	5.0%	4.8%	4.6%	4.4%	4.3%	4.1%	3.9%	6.5%
Global Water Resources Inc	$16.97	$0.02	15.0%	13.2%	11.3%	9.5%	7.6%	5.8%	3.9%	5.2%
Middlesex Water	$78.19	$0.27	3.7%	3.7%	3.8%	3.8%	3.8%	3.9%	3.9%	5.3%
New Jersey Resources	$40.59	$0.33	8.2%	7.5%	6.8%	6.0%	5.3%	4.6%	3.9%	8.4%
NiSource Inc.	$23.54	$0.22	8.8%	8.0%	7.2%	6.3%	5.5%	4.7%	3.9%	9.2%
Northwest Natural	$52.60	$0.48	4.3%	4.2%	4.2%	4.1%	4.0%	4.0%	3.9%	7.8%
ONE Gas Inc.	$75.20	$0.58	6.1%	5.7%	5.3%	5.0%	4.6%	4.3%	3.9%	7.6%
SJW Group	$60.91	$0.34	7.4%	6.9%	6.3%	5.7%	5.1%	4.5%	3.9%	6.8%
South Jersey Inds.	$23.95	$0.30	7.3%	6.7%	6.1%	5.6%	5.0%	4.5%	3.9%	10.4%
Southwest Gas	$67.37	$0.57	7.0%	6.5%	5.9%	5.4%	4.9%	4.4%	3.9%	8.2%
Spire Inc.	$73.61	$0.65	6.3%	5.9%	5.5%	5.1%	4.7%	4.3%	3.9%	8.2%
York Water Co. (The)	$48.51	$0.19	5.0%	4.8%	4.6%	4.5%	4.3%	4.1%	3.9%	5.6%

Sources and Notes:
[1]: Workpaper #1 to Schedule No. BV-6.
[2]: Workpaper #2 to Schedule No. BV-6.
[3]: Schedule No. BV-5, [6].
[4]: [3] - {([3] - [9])/ 6}.
[5]: [4] - {([3] - [9])/ 6}.
[6]: [5] - {([3] - [9])/ 6}.
[7]: [6] - {([3] - [9])/ 6}.
[8]: [7] - {([3] - [9])/ 6}.
[9]: BlueChip Economic Indicators, March 2021 This number is assumed to be the perpetual growth rate.
[10]: Workpaper #3 to Schedule No. BV-6.

Schedule No. BV-7

Overall After-Tax DCF Cost of Capital of the Sample

Panel A: Simple DCF Method (Quarterly)

Company	4th Quarter, 2020 S&P Bond Rating	4th Quarter, 2020 Preferred Equity Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	Portland General Electric's Representative Income Tax Rate	Overall Weighted After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Amer. States Water	A	-	7.3%	0.79	-	0.00	3.4%	0.21	27.0%	6.3%
Amer. Water Works	A	-	9.3%	0.67	-	0.00	3.4%	0.33	27.0%	7.1%
Artesian Res Corp	A	-	6.7%	0.66	-	0.00	3.4%	0.34	27.0%	5.2%
Atmos Energy	A	-	9.8%	0.66	-	0.00	3.4%	0.34	27.0%	7.3%
California Water	A	-	10.4%	0.68	-	0.00	3.4%	0.32	27.0%	7.9%
Chesapeake Utilities	A	-	7.9%	0.74	-	0.00	3.4%	0.26	27.0%	6.5%
Essential Utilities	A	-	7.4%	0.65	-	0.00	3.4%	0.35	27.0%	5.7%
Global Water Resources Inc	A	-	15.7%	0.75	-	0.00	3.4%	0.25	27.0%	12.3%
Middlesex Water	A	A	5.1%	0.82	3.4%	0.00	3.4%	0.18	27.0%	4.6%
New Jersey Resources	A	-	11.8%	0.59	-	0.00	3.4%	0.41	27.0%	7.9%
NiSource Inc.	BBB	BBB	12.9%	0.43	3.7%	0.04	3.7%	0.53	27.0%	7.1%
Northwest Natural	BBB	-	8.2%	0.56	-	0.00	3.7%	0.44	27.0%	5.8%
ONE Gas Inc.	A	-	9.4%	0.64	-	0.00	3.4%	0.36	27.0%	6.9%
SJW Group	A	-	9.9%	0.49	-	0.00	3.4%	0.51	27.0%	6.1%
South Jersey Inds.	BBB	-	12.8%	0.40	-	0.00	3.7%	0.60	27.0%	6.8%
Southwest Gas	BBB	-	10.6%	0.58	-	0.00	3.7%	0.42	27.0%	7.3%
Spire Inc.	A	A	10.1%	0.49	3.4%	0.03	3.4%	0.48	27.0%	6.2%
York Water Co. (The)	A	-	6.7%	0.81	-	0.00	3.4%	0.19	27.0%	5.9%
Simple Combined Sample Average			9.6%	0.63	3.5%	0.00	3.4%	0.36	27.0%	6.8%
Simple Gas Sample Average			10.4%	0.56	3.5%	0.01	3.5%	0.43	27.0%	6.9%
Simple Water Sample Average			8.7%	0.70	3.4%	0.00	3.4%	0.30	27.0%	6.8%

Sources and Notes:
[1]: Bloomberg as of March 31, 2021.
[2]: Preferred ratings were assumed equal to debt rating
[3]: Schedule No. BV-6; Panel A, [6].
[4]: Schedule No. BV-4, [1].
[5]: Workpaper #2 to Schedule No. BV-11, Panel C.
[6]: Schedule No. BV-4, [2].
[7]: Workpaper #2 to Schedule No. BV-11, Panel B.
[8]: Schedule No. BV-4, [3].
[9]: Provided by Portland General Electric.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

Schedule No. BV-7

Overall After-Tax DCF Cost of Capital of the Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	4th Quarter, 2020 S&P Bond Rating	4th Quarter, 2020 Preferred Equity Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	Portland General Electric's Representative Income Tax Rate	Overall Weighted After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Amer. States Water	A	-	6.0%	0.79	-	0.00	3.4%	0.21	27.0%	5.3%
Amer. Water Works	A	-	6.0%	0.67	-	0.00	3.4%	0.33	27.0%	4.8%
Artesian Res Corp	A	-	6.6%	0.66	-	0.00	3.4%	0.34	27.0%	5.2%
Atmos Energy	A	-	7.3%	0.66	-	0.00	3.4%	0.34	27.0%	5.6%
California Water	A	-	6.3%	0.68	-	0.00	3.4%	0.32	27.0%	5.1%
Chesapeake Utilities	A	-	5.7%	0.74	-	0.00	3.4%	0.26	27.0%	4.9%
Essential Utilities	A	-	6.5%	0.65	-	0.00	3.4%	0.35	27.0%	5.1%
Global Water Resources Inc	A	-	5.2%	0.75	-	0.00	3.4%	0.25	27.0%	4.5%
Middlesex Water	A	A	5.3%	0.82	3.4%	0.00	3.4%	0.18	27.0%	4.8%
New Jersey Resources	A	-	8.4%	0.59	-	0.00	3.4%	0.41	27.0%	5.9%
NiSource Inc.	BBB	BBB	9.2%	0.43	3.7%	0.04	3.7%	0.53	27.0%	5.5%
Northwest Natural	BBB	-	7.8%	0.56	-	0.00	3.7%	0.44	27.0%	5.6%
ONE Gas Inc.	A	-	7.6%	0.64	-	0.00	3.4%	0.36	27.0%	5.7%
SJW Group	A	-	6.8%	0.49	-	0.00	3.4%	0.51	27.0%	4.6%
South Jersey Inds.	BBB	-	10.4%	0.40	-	0.00	3.7%	0.60	27.0%	5.8%
Southwest Gas	BBB	-	8.2%	0.58	-	0.00	3.7%	0.42	27.0%	5.9%
Spire Inc.	A	A	8.2%	0.49	3.4%	0.03	3.4%	0.48	27.0%	5.3%
York Water Co. (The)	A	-	5.6%	0.81	-	0.00	3.4%	0.19	27.0%	5.0%
Multi-Stage Combined Sample Average			7.1%	0.63	3.5%	0.00	3.4%	0.36	27.0%	5.3%
Multi-Stage Gas Sample Average			8.1%	0.56	3.5%	0.01	3.5%	0.43	27.0%	5.6%
Multi-Stage Water Sample Average			6.0%	0.70	3.4%	0.00	3.4%	0.30	27.0%	4.9%

Sources and Notes:
[1]: Bloomberg as of March 31, 2021.
[2]: Preferred ratings were assumed equal to debt rating
[3]: Schedule No. BV-6, Panel B, [10].
[4]: Schedule No. BV-4, [1].
[5]: Workpaper #2 to Schedule No. BV-11, Panel C.
[6]: Schedule No. BV-4, [2].
[7]: Workpaper #2 to Schedule No. BV-11, Panel B.
[8]: Schedule No. BV-4, [3].
[9]: Provided by Portland General Electric.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

Schedule No. BV-8

DCF Cost of Equity at Portland General Electric's Proposed Capital Structure

Sample

	Overall After - Tax Cost of Capital [1]	Portland General Electric's Representative Regulatory % Debt [2]	Representative Cost of BBB Rated Utility Debt [3]	Portland General Electric's Representative Income Tax Rate [4]	Portland General Electric's Representative Regulatory % Equity [5]	Estimated Return on Equity [6]
Combined Sample						
Simple DCF Quarterly	6.8%	50.0%	3.7%	27.0%	50.0%	10.9%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Rate	5.3%	50.0%	3.7%	27.0%	50.0%	7.8%
Electric Sample						
Simple DCF Quarterly	6.8%	50.0%	3.7%	27.0%	50.0%	10.9%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Rate	4.9%	50.0%	3.7%	27.0%	50.0%	7.1%
Gas Sample						
Simple DCF Quarterly	6.9%	50.0%	3.7%	27.0%	50.0%	11.0%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Rate	5.6%	50.0%	3.7%	27.0%	50.0%	8.5%

Sources and Notes:
[1]: Schedule No. BV-7; Panels A-B, [10].
[2]: Provided by Portland General Electric.
[3]: Based on a BBB rating. Yield from Bloomberg as of March 31, 2021.
[4]: Provided by Portland General Electric.
[5]: Provided by Portland General Electric.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

Schedule No. BV-9 Risk-Free Rates

BCEI Forecast of 10 year U.S. Treasury Yield	**[a]**	**2.10%**
Long-run Average of 20 year U.S. Treasury Yield	[b]	5.01%
Long-run Average of 10 year U.S. Treasury Yield	[c]	4.53%
Maturity Premium	**[d] = [b] - [c]**	**0.50%**
Base Projection of 20 year U.S. Treasury Yield	**[e] = [a] + [d]**	**2.60%**

Sources and Notes:
[a]: Blue Chip Economic Indicators, March 2021. Average projection of 2022 and 2023 Yiel
[b], [c]: Bloomberg as of 3/31/2021, see Workpaper #1 to Schedule No. BV-9.

Schedule No. BV-10

Risk Positioning Cost of Equity of the Sample (Using Value Line Betas)

Panel A: Scenario 1 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%

Company	Long-Term Risk-Free Rate	Value Line Betas	Long-Term Market Risk Premium	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Amer. States Water	2.80%	0.65	7.25%	7.5%	8.0%
Amer. Water Works	2.80%	0.85	7.25%	9.0%	9.2%
Artesian Res Corp	2.80%	0.75	7.25%	8.2%	8.6%
Atmos Energy	2.80%	0.80	7.25%	8.6%	8.9%
California Water	2.80%	0.65	7.25%	7.5%	8.0%
Chesapeake Utilities	2.80%	0.80	7.25%	8.6%	8.9%
Essential Utilities	2.80%	0.95	7.25%	9.7%	9.8%
Global Water Resources Inc	2.80%	0.75	7.25%	8.2%	8.6%
Middlesex Water	2.80%	0.70	7.25%	7.9%	8.3%
New Jersey Resources	2.80%	0.95	7.25%	9.7%	9.8%
NiSource Inc.	2.80%	0.85	7.25%	9.0%	9.2%
Northwest Natural	2.80%	0.80	7.25%	8.6%	8.9%
ONE Gas Inc.	2.80%	0.80	7.25%	8.6%	8.9%
SJW Group	2.80%	0.85	7.25%	9.0%	9.2%
South Jersey Inds.	2.80%	1.05	7.25%	10.4%	10.3%
Southwest Gas	2.80%	0.95	7.25%	9.7%	9.8%
Spire Inc.	2.80%	0.85	7.25%	9.0%	9.2%
York Water Co. (The)	2.80%	0.80	7.25%	8.6%	8.9%

Sources and Notes:
[1], [3]: Villadsen Direct Testimony.
[2]: From Valueline Investment Analyzer as of March 31, 2021.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-10

Risk Positioning Cost of Equity of the Sample (Using Value Line Betas)

Panel B: Scenario 2 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%

Company	Long-Term Risk-Free Rate	Value Line Betas	Long-Term Market Risk Premium	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Amer. States Water	2.80%	0.65	8.00%	8.0%	8.5%
Amer. Water Works	2.80%	0.85	8.00%	9.6%	9.8%
Artesian Res Corp	2.80%	0.75	8.00%	8.8%	9.2%
Atmos Energy	2.80%	0.80	8.00%	9.2%	9.5%
California Water	2.80%	0.65	8.00%	8.0%	8.5%
Chesapeake Utilities	2.80%	0.80	8.00%	9.2%	9.5%
Essential Utilities	2.80%	0.95	8.00%	10.4%	10.5%
Global Water Resources Inc	2.80%	0.75	8.00%	8.8%	9.2%
Middlesex Water	2.80%	0.70	8.00%	8.4%	8.9%
New Jersey Resources	2.80%	0.95	8.00%	10.4%	10.5%
NiSource Inc.	2.80%	0.85	8.00%	9.6%	9.8%
Northwest Natural	2.80%	0.80	8.00%	9.2%	9.5%
ONE Gas Inc.	2.80%	0.80	8.00%	9.2%	9.5%
SJW Group	2.80%	0.85	8.00%	9.6%	9.8%
South Jersey Inds.	2.80%	1.05	8.00%	11.2%	11.1%
Southwest Gas	2.80%	0.95	8.00%	10.4%	10.5%
Spire Inc.	2.80%	0.85	8.00%	9.6%	9.8%
York Water Co. (The)	2.80%	0.80	8.00%	9.2%	9.5%

Sources and Notes:
[1], [3]: Villadsen Direct Testimony.
[2]: From Valueline Investment Analyzer as of March 31, 2021.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-11

Overall After-Tax Risk Positioning Cost of Capital of the Sample (Using Value Line Betas)

Panel A: CAPM Cost of Equity Scenario 1 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%

Company	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity	5-Year Average Common Equity to Market Value Ratio	Weighted - Average Cost of Preferred Equity	5-Year Average Preferred Equity to Market Value Ratio	Weighted- Average Cost of Debt	5-Year Average Debt to Market Value Ratio	Electric's Representative Income Tax Rate	Overall After-Tax Cost of Capital (CAPM)	Overall After-Tax Cost of Capital (ECAPM 1.5%)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Amer. States Water	7.5%	8.0%	0.82	-	0.00	3.4%	0.18	27.0%	6.6%	7.0%
Amer. Water Works	9.0%	9.2%	0.66	-	0.00	3.4%	0.34	27.0%	6.7%	6.9%
Artesian Res Corp	8.2%	8.6%	0.70	-	0.00	3.4%	0.30	27.0%	6.5%	6.8%
Atmos Energy	8.6%	8.9%	0.71	-	0.00	3.4%	0.29	27.0%	6.8%	7.0%
California Water	7.5%	8.0%	0.70	-	0.00	3.4%	0.30	27.0%	6.0%	6.4%
Chesapeake Utilities	8.6%	8.9%	0.72	-	0.00	3.4%	0.28	27.0%	6.9%	7.1%
Essential Utilities	9.7%	9.8%	0.73	-	0.00	3.4%	0.27	27.0%	7.7%	7.8%
Global Water Resources Inc	8.2%	8.6%	0.66	-	0.00	3.4%	0.34	27.0%	6.3%	6.5%
Middlesex Water	7.9%	8.3%	0.80	3.4%	0.00	3.4%	0.19	27.0%	6.8%	7.2%
New Jersey Resources	9.7%	9.8%	0.70	-	0.00	3.4%	0.30	27.0%	7.5%	7.5%
NiSource Inc.	9.0%	9.2%	0.46	3.7%	0.03	3.7%	0.51	27.0%	5.6%	5.7%
Northwest Natural	8.6%	8.9%	0.65	-	0.00	3.7%	0.35	27.0%	6.5%	6.7%
ONE Gas Inc.	8.6%	8.9%	0.71	-	0.00	3.4%	0.29	27.0%	6.8%	7.0%
SJW Group	9.0%	9.2%	0.65	-	0.00	3.4%	0.35	27.0%	6.7%	6.8%
South Jersey Inds.	10.4%	10.3%	0.52	-	0.00	3.7%	0.48	27.0%	6.7%	6.7%
Southwest Gas	9.7%	9.8%	0.63	-	0.00	3.7%	0.37	27.0%	7.1%	7.1%
Spire Inc.	9.0%	9.2%	0.55	3.4%	0.01	3.4%	0.44	27.0%	6.0%	6.1%
York Water Co. (The)	8.6%	8.9%	0.82	-	0.00	3.4%	0.18	27.0%	7.5%	7.7%
Combined Sample Average	8.8%	9.0%	0.68	3.5%	0.00	3.4%	0.32	27.0%	6.7%	6.9%
Gas Sample Average	9.1%	9.3%	0.63	3.5%	0.00	3.5%	0.37	27.0%	6.7%	6.8%
Water Sample Average	8.4%	8.7%	0.73	3.4%	0.00	3.4%	0.27	27.0%	6.8%	7.0%

Sources and Notes:
[1]: Schedule No. BV-10; Panel A, [4].
[2]: Schedule No. BV-10; Panel A, [5].
[3]: Schedule No. BV-4, [4].
[4]: Workpaper #2 to Schedule No. BV-11, Panel C.
[5]: Schedule No. BV-4, [5].
[6]: Workpaper #2 to Schedule No. BV-11, Panel B.
[7]: Schedule No. BV-4, [6].
[8]: Provided by Portland General Electric.
[9] = [1] x [3] + [4] x [5] + [6] x [7] x (1 - [8])
[10] = [2] x [3] + [4] x [5] + [6] x [7] x (1 - [8])

Schedule No. BV-11

Overall After-Tax Risk Positioning Cost of Capital of the Sample (Using Value Line Betas)

Panel B: CAPM Cost of Equity Scenario 2 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%

Company	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity	5-Year Average Common Equity to Market Value Ratio	Weighted - Average Cost of Preferred Equity	5-Year Average Preferred Equity to Market Value Ratio	Weighted- Average Cost of Debt	5-Year Average Debt to Market Value Ratio	Electric's Representative Income Tax Rate	Overall After-Tax Cost of Capital (CAPM)	Overall After-Tax Cost of Capital (ECAPM 1.5%)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	capmlt	ecapmlt2	capm_equity_ratio	average	capm_pref_ratio	average	capm_debt_ratio		CAPM	ECAPM2
Amer. States Water	8.0%	8.5%	0.82	-	0.00	3.4%	0.18	27.0%	7.0%	7.4%
Amer. Water Works	9.6%	9.8%	0.66	-	0.00	3.4%	0.34	27.0%	7.1%	7.3%
Artesian Res Corp	8.8%	9.2%	0.70	-	0.00	3.4%	0.30	27.0%	6.9%	7.2%
Atmos Energy	9.2%	9.5%	0.71	-	0.00	3.4%	0.29	27.0%	7.2%	7.4%
California Water	8.0%	8.5%	0.70	-	0.00	3.4%	0.30	27.0%	6.3%	6.7%
Chesapeake Utilities	9.2%	9.5%	0.72	-	0.00	3.4%	0.28	27.0%	7.3%	7.5%
Essential Utilities	10.4%	10.5%	0.73	-	0.00	3.4%	0.27	27.0%	8.2%	8.3%
Global Water Resources Inc	8.8%	9.2%	0.66	-	0.00	3.4%	0.34	27.0%	6.7%	6.9%
Middlesex Water	8.4%	8.9%	0.80	3.4%	0.00	3.4%	0.19	27.0%	7.2%	7.6%
New Jersey Resources	10.4%	10.5%	0.70	-	0.00	3.4%	0.30	27.0%	8.0%	8.0%
NiSource Inc.	9.6%	9.8%	0.46	3.7%	0.03	3.7%	0.51	27.0%	5.9%	6.0%
Northwest Natural	9.2%	9.5%	0.65	-	0.00	3.7%	0.35	27.0%	6.9%	7.1%
ONE Gas Inc.	9.2%	9.5%	0.71	-	0.00	3.4%	0.29	27.0%	7.2%	7.4%
SJW Group	9.6%	9.8%	0.65	-	0.00	3.4%	0.35	27.0%	7.1%	7.2%
South Jersey Inds.	11.2%	11.1%	0.52	-	0.00	3.7%	0.48	27.0%	7.2%	7.1%
Southwest Gas	10.4%	10.5%	0.63	-	0.00	3.7%	0.37	27.0%	7.5%	7.6%
Spire Inc.	9.6%	9.8%	0.55	3.4%	0.01	3.4%	0.44	27.0%	6.4%	6.5%
York Water Co. (The)	9.2%	9.5%	0.82	-	0.00	3.4%	0.18	27.0%	8.0%	8.2%
Combined Sample Average	9.4%	9.6%	0.68	3.5%	0.00	3.4%	0.32	27.0%	7.1%	7.3%
Gas Sample Average	9.8%	10.0%	0.63	3.5%	0.00	3.5%	0.37	27.0%	7.1%	7.2%
Water Sample Average	9.0%	9.3%	0.73	3.4%	0.00	3.4%	0.27	27.0%	7.2%	7.4%

Sources and Notes:
[1]: Schedule No. BV-10; Panel B, [4].
[2]: Schedule No. BV-10; Panel B, [5].
[3]: Schedule No. BV-4, [4].
[4]: Workpaper #2 to Schedule No. BV-11, Panel C.
[5]: Schedule No. BV-4, [5].
[6]: Workpaper #2 to Schedule No. BV-11, Panel B.
[7]: Schedule No. BV-4, [6].
[8]: Provided by Portland General Electric.
[9] = [1] x [3] + [4] x [5] + [6] x [7] x (1 - [8])
[10] = [2] x [3] + [4] x [5] + [6] x [7] x (1 - [8])

Schedule No. BV-12

Risk Positioning Cost of Equity at Portland General Electric's Proposed Capital Structure

Sample

Using Value Line Betas

	Overall After-Tax Cost of Capital (Scenario 1)	Overall After-Tax Cost of Capital (Scenario 2)	Portland General Electric's Representative Regulatory % Debt	Representative Cost of BBB-Rated Utility Debt	Portland General Electric's Representative Income Tax Rate	Portland General Electric's Regulatory % Preferred Equity	Portland General Electric's Cost of Preferred Equity	Portland General Electric's Representative Regulatory % Equity	Estimated Return on Equity (Scenario 1)	Estimated Return on Equity (Scenario 2)
	[1]	[2]	[3]	[4]	[5]			[6]	[7]	[8]
Combined Sample										
CAPM using Value Line Betas	6.7%	7.1%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	10.7%	11.5%
ECAPM (1.50%) using Value Line Betas	6.9%	7.3%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	11.1%	11.9%
Water Sample										
CAPM using Value Line Betas	6.8%	7.2%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	10.8%	11.6%
ECAPM (1.50%) using Value Line Betas	7.0%	7.4%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	11.3%	12.1%
Gas Sample										
CAPM using Value Line Betas	6.7%	7.1%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	10.6%	11.4%
ECAPM (1.50%) using Value Line Betas	6.8%	7.2%	50.0%	3.7%	27.0%	0.0%	3.7%	50.0%	10.8%	11.7%

Sources and Notes:
[1]: Schedule No. BV-11; Panel A, [9] - [10].
[2]: Schedule No. BV-11; Panel B, [9] - [10].
[3]: Provided by Portland General Electric.
[4]: Based on a BBB rating. Yield from Bloomberg as of March 31, 2021.
[5]: Provided by Portland General Electric.
[6]: Provided by Portland General Electric.
[7]: {[1] - ([3] x [4] x (1 - [5])}/ [6]
[8]: {[2] - ([3] x [4] x (1 - [5]))}/ [6]

Scenario 1: Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%.
Scenario 2: Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%.

Schedule No. BV-13

Hamada Adjustment to Obtain Unlevered Asset Beta

Company		Value Line Betas	Debt Beta	5-Year Average Common Equity to Market Value Ratio	5-Year Average Preferred Equity to Market Value Ratio	5-Year Average Debt to Market Value Ratio	Portland General Electric's Representative Income Tax Rate	Asset Beta: Without Taxes	Asset Beta: With Taxes
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Amer. States Water	*	0.65	0.05	0.82	0.00	0.18	27.0%	0.54	0.57
Amer. Water Works	*	0.85	0.05	0.66	0.00	0.34	27.0%	0.58	0.63
Artesian Res Corp	*	0.75	0.05	0.70	0.00	0.30	27.0%	0.54	0.58
Atmos Energy	*	0.80	0.05	0.71	0.00	0.29	27.0%	0.58	0.63
California Water	*	0.65	0.05	0.70	0.00	0.30	27.0%	0.47	0.51
Chesapeake Utilities	*	0.80	0.05	0.72	0.00	0.28	27.0%	0.59	0.63
Essential Utilities	*	0.95	0.05	0.73	0.00	0.27	27.0%	0.70	0.76
Global Water Resources Inc	*	0.75	0.05	0.66	0.00	0.34	27.0%	0.51	0.56
Middlesex Water	*	0.70	0.05	0.80	0.00	0.19	27.0%	0.57	0.60
New Jersey Resources	*	0.95	0.05	0.70	0.00	0.30	27.0%	0.68	0.73
NiSource Inc.	*	0.85	0.10	0.46	0.03	0.51	27.0%	0.45	0.50
Northwest Natural	*	0.80	0.10	0.65	0.00	0.35	27.0%	0.55	0.60
ONE Gas Inc.	*	0.80	0.05	0.71	0.00	0.29	27.0%	0.58	0.62
SJW Group	*	0.85	0.05	0.65	0.00	0.35	27.0%	0.57	0.62
South Jersey Inds.	*	1.05	0.10	0.52	0.00	0.48	27.0%	0.60	0.67
Southwest Gas	*	0.95	0.10	0.63	0.00	0.37	27.0%	0.63	0.69
Spire Inc.	*	0.85	0.05	0.55	0.01	0.44	27.0%	0.49	0.55
York Water Co. (The)	*	0.80	0.05	0.82	0.00	0.18	27.0%	0.66	0.70
Combined Sample Average		0.82	0.06	0.68	0.00	0.32	0.27	0.57	0.62
Gas Sample Average		0.87	0.07	0.63	0.00	0.37	0.27	0.57	0.63
Water Sample Average		0.77	0.05	0.73	0.00	0.27	0.27	0.57	0.61

Sources and Notes:
[1]: Workpaper # 1 to Schedule No. BV-10, [1].
[2]: Workpaper #1 to Schedule No. BV-13, [7].
[3]: Schedule No. BV-4, [4].
[4]: Schedule No. BV-4, [5].
[5]: Schedule No. BV-4, [6].
[6]: Portland General Electric's Representative Tax Rate.
[7]: [1]*[3] + [2]*([4] + [5]).
[8]: {[1]*[3] + [2]*([4]+[5]*(1-[6]))} / {[3] + [4] + [5]*(1 -[6])}.

Schedule No. BV-14

Sample Average Asset Beta Relevered at Portland General Electric's Proposed Capital Structure

	Asset Beta	Assumed Debt Beta	Portland General Electric's Representative Regulatory % Debt	Portland General Electric's Representative Income Tax Rate	Portland General Electric's Representative Regulatory % Equity	Estimated Equity Beta
	[1]	[2]	[3]	[4]	[5]	[6]
Combined Sample						
Asset Beta Without Taxes	0.57	0.10	50.0%	27.0%	50.0%	1.04
Asset Beta With Taxes	0.62	0.10	50.0%	27.0%	50.0%	1.00
Water Sample						
Asset Beta Without Taxes	0.57	0.10	50.0%	27.0%	50.0%	1.05
Asset Beta With Taxes	0.61	0.10	50.0%	27.0%	50.0%	0.99
Gas Sample						
Asset Beta Without Taxes	0.57	0.10	50.0%	27.0%	50.0%	1.04
Asset Beta With Taxes	0.63	0.10	50.0%	27.0%	50.0%	1.01

Sources and Notes:
[1]: Schedule No. BV-13, [7] - [8].
[2]: Villadsen Testimony.
[3]: Provided by Portland General Electric.
[4]: Portland General Electric's Representative Tax Rate.
[5]: Provided by Portland General Electric.
[6]: [1] + [3]/[5]*([1] - [2]) without taxes, [1] + [3]*(1 - [4])/[5]*([1] - [2]) with taxes.

Schedule No. BV-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel A: Scenario 1 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 7.25%

Company	Long-Term Risk-Free Rate	Hamada Adjusted Equity Betas	Long-Term Market Risk	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Combined Sample					
Asset Beta Without Taxes	2.80%	1.04	7.25%	10.4%	10.3%
Asset Beta With Taxes	2.80%	1.00	7.25%	10.0%	10.0%
Water Sample					
Asset Beta Without Taxes	2.80%	1.05	7.25%	10.4%	10.3%
Asset Beta With Taxes	2.80%	0.99	7.25%	10.0%	10.0%
Gas Sample					
Asset Beta Without Taxes	2.80%	1.04	7.25%	10.4%	10.3%
Asset Beta With Taxes	2.80%	1.01	7.25%	10.1%	10.1%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Schedule No. BV-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Schedule No. BV-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel B: Scenario 2 - Long-Term Risk Free Rate of 2.80%, Long-Term Market Risk Premium of 8.00%

Company	Long-Term Risk-Free Rate	Hamada Adjusted Equity Betas	Long-Term Market Risk	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Combined Sample					
Asset Beta Without Taxes	2.80%	1.04	8.00%	11.2%	11.1%
Asset Beta With Taxes	2.80%	1.00	8.00%	10.8%	10.8%
Water Sample					
Asset Beta Without Taxes	2.80%	1.05	8.00%	11.2%	11.1%
Asset Beta With Taxes	2.80%	0.99	8.00%	10.7%	10.7%
Gas Sample					
Asset Beta Without Taxes	2.80%	1.04	8.00%	11.1%	11.1%
Asset Beta With Taxes	2.80%	1.01	8.00%	10.9%	10.9%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Schedule No. BV-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

EXHIBIT 905: Technical Appendix to Cost of Equity Estimation

This technical appendix contains methodological details related to my implementations of the DCF and CAPM / ECAPM models. It also contains a discussion of both the basic finance principles and the specific standard formulations of the financial leverage adjustments employed to determine the cost of equity for a company with the level of financial risk inherent in Portland General's requested regulatory capital structure.

Table of Contents

I. 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:

$$P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \qquad (1)$$

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

$$P_0 = \frac{D_1}{r-g} \qquad (2)$$

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,

$$r = \frac{D_1}{P_0} + g = \frac{D_0 \times (1+g)}{P_0} + g \qquad (3)$$

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.

[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. 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 5-years without a gap or a dividend cut (on per share basis). Additionally, although some utility companies have engaged in share repurchase programs, the companies in my proxy group do not distribute substantial cash flows by means other than dividends.

C. DCF Model Inputs

1. Dividends and Prices

As described above, DCF models are forward-looking, comparing the *current* price of a stock to its expected *future* dividends to estimate the required expected return demanded by the market for that stock (i.e., the cost of equity). Therefore, the models demand the current market price and currently prevailing forecasts of future dividends as inputs.

The stock price input I employ for each proxy group company is the average of the closing stock prices for the 15 trading days ending on the date of my analysis. This guards against biases that may arise on a single trading day, yet is consistent with using current stock prices.

2. Company Specific Growth Rates

*a. **Analysts' Forecasted** Growth Rates*

Finding the right growth rate(s) is usually the "hard part" of applying the DCF model, which is sometimes criticized due to what has been called "optimism bias" in the earnings growth rate forecasts of security analysts. Optimism bias is defined as 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.

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, 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

2 A. Hovakimian and E. Saenyasiri, "Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation," *Financial Analysts Journal*, vol. 66, 2010.

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; and (iii) Michel, J-S., Pandes J.A. (2012), "Are Analysts Really Too Optimistic?" downloaded from http://www.efmaefm.org.

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.

the required expected return on an asset is proportional to that asset's risk relative to the market as measured by its "beta". More precisely, the CAPM states that the cost of capital for an investment *S* (e.g., a particular common stock), is given by the following equation:

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \tag{4}$$

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 a 20-year government bond. Specifically, I rely on a forecast of what Government bond yields will be mid-way through the 2022-2024 period. Relying on the May 2021 Blue Chip Economic Indicators ("BCEI") for 2022 and the March 2021 BCEI for 2023 and 2024, the estimated yield on 10-year U.S. Treasury bond yields will be 2.1% in 2022, 2.3% in 2023, and 2.5% in 2024, so I rely on the 2023 (midpoint) value of 2.3%.[6] I then adjust this value upwards

[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] Wolters Kluwer Blue Chip Economic Indicators and PwC Analysis, Consensus Forecasts, March 2021, p. 3 and p. 14 and BCEI May 2021 p. 3.

by 50 basis points to reflect the historical maturity premium for the 20-year U.S. Treasury bond yield over the 10 U.S. Treasury bond yield.[7] This gives me a risk-free rate of 2.80%.[8]

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 the 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 7.15%.[9]

b. Forward Looking Market Equity Risk Premium

An alternative approach to estimating the MRP eschews historical averages in favor of using current market information and forecasts to infer the expected return on the market as a whole, which can then be compared to prevailing government bond yields to estimate the equity risk premium. Bloomberg performs such estimates of country-specific MRPs by implementing the DCF model on the market as a whole—using forecast market-wide dividend yields and current level on market indexes; for the U.S. Bloomberg performs a multi-stage DCF using dividend-paying stocks in the S&P 500 to infer the expected market return.

When calculated relative to 20-year Treasury bond yields, Bloomberg's estimate of the forward-looking market-implied MRP over the two week period before April 30 was slightly above 8% This Bloomberg forward-looking MRP estimate is above the historical long-term average.

[7] This maturity premium is estimated by comparing the average excess yield on 20-year versus 10-year Government Bonds over the period 1990-2020, using data from Bloomberg.

[8] In prior proceedings I have adjusted for an elevated spread between utility bond yields and government bond yields. As there currently is no such elevated spread, I do not make any adjustments and do not discuss the issue further.

[9] Duff & Phelps, Cost of Capital Navigator, U.S. Cost of Capital Module 2020.

C. The Empirical CAPM

1. Description of the ECAPM

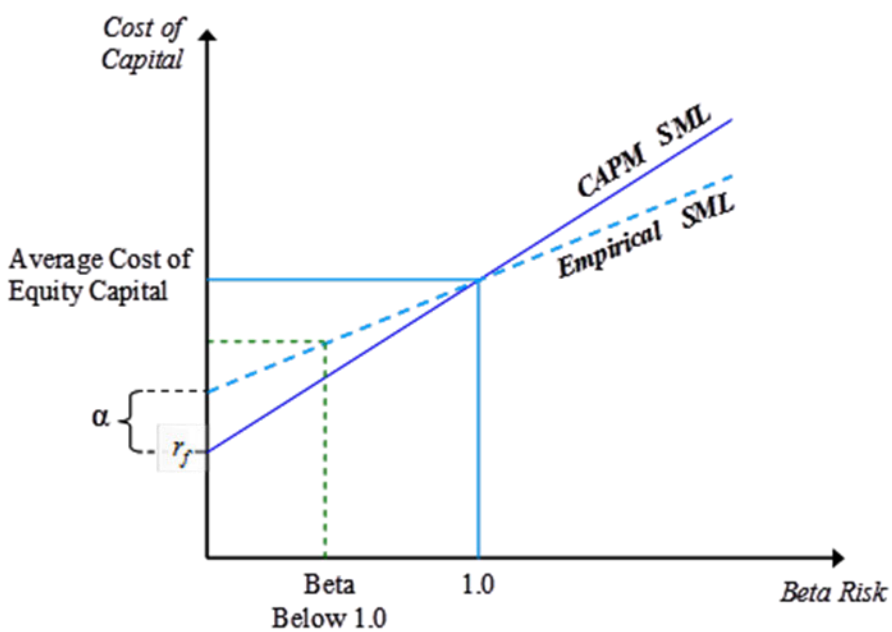
Empirical research has shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. A number of variations on the original 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,

$$\boldsymbol{r_S = r_f + \alpha + \beta_S \times (MRP - \alpha)} \qquad (6)$$

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- 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.
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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.[10] 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.[11]

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).

[10] This is also a common valuation problem in general business contexts.

[11] 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

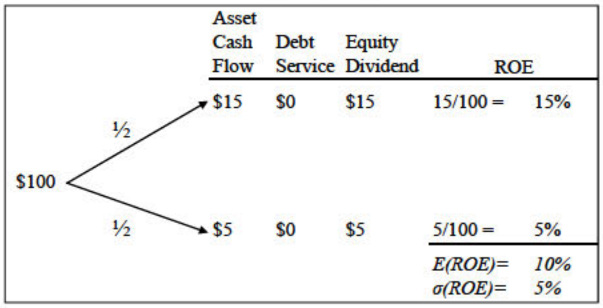
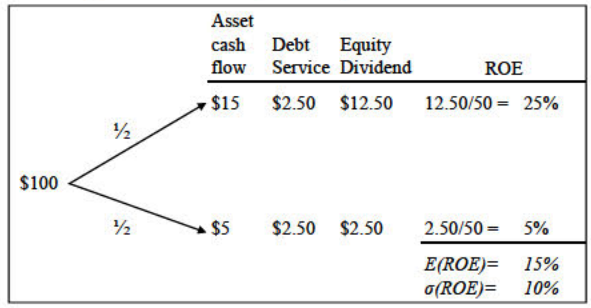


Figure B-5: 50/50 Capital Structure



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.[12] The expected return to the underlying asset is therefore equal to the value weighted

[12] 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.[13]

$$\boldsymbol{r}^* = \frac{E}{V} \times r_E + \frac{D}{V} \times r_D(1 - \tau_c) \qquad (7)$$

where r_D is the market cost of debt,
r_E is the market cost of equity,
τ_c is the corporate income tax rate,
D is the market value of the firm's debt,
E is the market value of the firm's equity, and
$V = E + D$ is the total market value of the firm.

Since the overall cost of capital is the cost of capital for the underlying asset risk, and this is comparable across companies, it is reasonable to believe that the overall cost of capital of the underlying companies should also be comparable, so long as capital structures do not involve unusual leverage ratios compared to other companies in the industry.[14]

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.[15] 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

[13] 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.

[14] 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.

[15] 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,[16] 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,[17] the latter can still be shown to be constant across a broad range of capital structures.[18]

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.[19]

2. Unlevering and Relevering Betas in the CAPM (Hamada Adjustment)

An alternative approach to account for the impact of financial risk is to examine the impact of leverage on beta. Notice that this means working within the CAPM framework as the methodology cannot be applied directly to the DCF models.

16 Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

17 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.

18 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.

19 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:[20]

$$V = V_U + PV(ITS) \tag{8}$$

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

[20] 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.[21]

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 company's capital structure, and CAPM reapplied with this levered beta, which reflects both the business and financial risk of the target company.

[21] Berk, J. & DeMarzo, P., *Corporate Finance, 2nd Edition.* 2011 Prentice Hall, p. 389.

Hamada adjustment procedures—so-named for Professor Robert S. Hamada who contributed to their development[22]—are ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

[22] 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.

Dr. Bente Villadsen is a principal at The Brattle Group**'s** Boston office. Her 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 serves 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, Michigan, New Mexico, New York, Oregon, and Washington as well as in the provinces of Alberta and Ontario.
- 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.
- 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 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 12 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.

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

"A Review of International Approaches to Regulated Rates of Return," (with J. Anthony, T. Brown, L. Figurelli, D. Harris, and N. Nguyen) published by the *Australian Energy Regulator*, September 2020.

"Global Impacts and Implications of COVID-19 on Utility Finance," (with R. Mudge, F. Graves, J. Figueroa, T. Counts, L. Mwalenga, and S. Pant), *The Brattle Group*, July 2020.

"Impact of New Tax Law on Utilities' Deferred Taxes," (with Mike Tolleth and Elliott Metzler), *CRRI 37'th Annual Eastern Conference*, June, 2018.

"Implications of the New Tax Law for Regulated Utilities," The Brattle Group, January 2018.

"Using Electric and Gas Forwards to Manage Market Risks: When a power purchase agreement with a utility is not possible, standard forward contracts can act as viable hedging instruments," *North American Windpower*, May 2017, pp. 34-37.

"*Managing Price Risk for Merchant Renewable Investments: Role of Market Interactions and Dynamics on Effective Hedging Strategies*," (with Onur Aydin and Frank Graves), Brattle Whitepaper, January 2017.

"Aurizon Network 2016 Access Undertaking: Aspects of the WACC," (with Mike Tolleth), filed with the *Queensland Competition Authority*, Australia, November 2016.

"Report on Gas LDC multiples," with Michael J. Vilbert, *Alaska Industrial Development and Export Authority*, May 2015.

"Aurizon Network 2014 Draft Access Undertaking: Comments on Aspects of the WACC," prepared for Aurizon Network and submitted to the *Queensland Competition Authority*, December 2014

"Brattle Review of AE Planning Methods and Austin Task Force Report." (with Frank C. Graves) September 24, 2014.

Report on "Cost of Capital for Telecom Italia's Regulated Business" with Stewart C. Myers and Francesco Lo Passo before the *Communications Regulatory Authority of Italy* ("AGCOM"), March 2014. *Submitted in Italian.*

"Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century," (with J. Wharton and H. Bishop), prepared for the *National Association of Water Companies*, October 2013.

"Estimating the Cost of Debt," (with T. Brown), prepared for the Dampier Bunbury Pipeline and filed with the *Economic Regulation Authority*, Western Australia, March 2013.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, M.J. Vilbert, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the *Australian Energy Regulator* and the *Economic Regulation Authority*, Western Australia, February 2013.

"Calculating the Equity Risk Premium and the Risk Free Rate," (with Dan Harris and Francesco LoPasso), prepared for *NMa and Opta, the Netherlands*, November 2012.

"Shale Gas and Pipeline Risk: Earnings Erosion in a More Competitive World," (with Paul R. Carpenter, A. Lawrence Kolbe, and Steven H. Levine), *Public Utilities Fortnightly*, April 2012.

"Survey of Cost of Capital Practices in Canada," (with Michael J. Vilbert and Toby Brown), prepared for *British Columbia Utilities Commission*, May 2012.

"Public Sector Discount Rates" (with rank Graves, Bin Zhou), *Brattle* white paper, September 2011

"FASB Accounting Rules and Implications for Natural Gas Purchase Agreements," (with Fiona Wang), *American Clean Skies Foundation*, February 2011.

"IFRS and You: How the New Standards Affect Utility Balance Sheets," (with Amit Koshal and Wyatt Toolson), *Public Utilities Fortnightly*, December 2010.

"Corporate Pension Plans: New Developments and Litigation," (with George Oldfield and Urvashi Malhotra), Finance Newsletter, Issue 01, *The Brattle Group*, November 2010.

"Review of Regulatory Cost of Capital Methodologies," (with Michael J. Vilbert and Matthew Aharonian), *Canadian Transportation Agency*, September 2010.

"Building Sustainable Efficiency Businesses: Evaluating Business Models," (with Joe Wharton and Peter Fox-Penner), *Edison Electric Institute*, August 2008.

"Understanding Debt Imputation Issues," (with Michael J. Vilbert and Joe Wharton and *The Brattle Group* listed as an author), *Edison Electric Institute*, June 2008.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," *Public Utilities Fortnightly*, August 2005 (with A. Lawrence Kolbe and Michael J. Vilbert).

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," (with A. Lawrence Kolbe and Michael J. Vilbert, and with "*The Brattle Group*" listed as author), *Edison Electric Institute,* April 2005.

"Communication and Delegation in Collusive Agencies," *Journal of Accounting and Economics*, Vol. 19, 1995.

"Beta Distributed Market Shares in a Spatial Model with an Application to the Market for Audit Services" (with M. Hviid), *Review of Industrial Organization*, Vol. 10, 1995.

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"FERC's new ROE methodology for pipelines and electric transmission," (with Michael J. Vilbert) *UBS Fireside Chat*, June 24, 2020.

"Managing Price Risk for Merchant Renewable Investments," (with Onur Aydin) *EIA Electricity Pricing Workgroup* (webinar), April 30, 2019.

"Decoupling and its Impact on Cost of Capital" presented to *SURFA Members and Friends*, February 27, 2019.

"Current Issues in Cost of Capital" presented to *EEI Members*, July, 2018-19.

"Introduction to Capital Structure & Liability Management", *the American Gas Association/Edison Electric Institute "Introduction and Advanced Public Utility Accounting Courses",* August 2018-2019.

"Lessons from the U.S. and Australia" presented at *Seminar on the Cost of Capital in Regulated Industries: Time for a Fresh Perspective?* Brussels, October 2017.

"Should Regulated Utilities Hedge Fuel Cost and if so, How?" presented at *SURFA's 49 Financial Forum*, April 20-21, 2017.

"Transmission: The Interplay Between FERC Rate Setting at the Wholesale Level and Allocation to Retail Customers," (with Mariko Geronimo Aydin) presented at *Law Seminars International: Electric Utility Rate Cases*, March 16-17, 2017.

"Capital Structure and Liability Management," *American Gas Association and Edison Electric Institute Public Utility Accounting Course*, August 2015-2017.

"Current Issues in Cost of Capital," *Edison Electric Institute Advanced Rate School*, July 2013-2017.

"Alternative Regulation and Rate Making Approaches for Water Companies," *Society of Depreciation Professionals Annual Conference*, September 2014.

"Capital Investments and Alternative Regulation," *National Association of Water Companies Annual Policy Forum*, December 2013.

"Accounting for Power Plant," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"GAAP / IFRS Convergence," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"International Innovations in Rate of Return Determination," *Society of Utility Financial and Regulatory Analysts' Financial Forum*, April 2012.

"Utility Accounting and Financial Analysis: The Impact of Regulatory Initiatives on Accounting and Credit Metrics," 1.5 day seminar, EUCI, Atlanta, May 2012.

"Cost of Capital Working Group Eforum," *Edison Electric Institute webinar*, April 2012.

"Issues Facing the Global Water Utility Industry" Presented to Sensus' Executive Retreat, Raleigh, NC, July 2010.

"Regulatory Issues from GAAP to IFRS," NASUCA *2009 Annual Meeting*, Chicago, November 2009.

"Subprime Mortgage-Related Litigation: What to Look for and Where to Look," *Law Seminars International: Damages in Securities Litigation*, Boston, May 2008.

"Evaluating Alternative Business / Inventive Models," (with Joe Wharton). *EEI Workshop, Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, Washington DC, December 2007.

"Deferred Income Taxes and IRS's NOPR: Who should benefit?" *NASUCA Annual Meeting*, Anaheim, CA, November 2007.

"Discussion of 'Are Performance Measures Other Than Price Important to CEO Incentives?'" *Annual Meeting of the American Accounting Association*, 2000.

"Contracting and Income Smoothing in an Infinite Agency Model: A Computational Approach," (with R.T. Boylan) *Business and Management Assurance Services Conference*, Austin 2000.

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Direct Testimony on Cost of Capital on behalf of California-American Water Company, *California Public Utilities Commission*, Application No. 21-05-___, May 2021.

Prefiled Direct Testimony on cost of equity on behalf of Southern Star Central Gas Pipeline, *Federal Energy Regulatory Commission*, Docket RP21-778-000, April 2021.

Direct Testimony re. the prospective excessive earnings test on behalf of Cleveland Electric Illuminating Company and the Toledo Edison Company, *Public Utilities Commission of Ohio*, Case Nos. 20-1034-EL UNC and 20-1476-EL-UNC, March 2021.

Rebuttal Testimony re. the discount rate for property valuation in tax assessment on behalf of Union Pacific Railroad, *Utah District Court*, Case No. 2:18-cv-00630-DAK_DBP (Union Pacific Railroad v. Utah State Tax Commission et al), February 2021.

Direct Testimony on the cost of equity on behalf of Orange & Rockland Utilities submitted to the *New York Department of Public Service*, Case No. 21-E-0074, January 2021.

Direct Testimony and Rebuttal Testimony on the cost of equity on behalf of Nicor Gas submitted to the *Illinois Commerce Commission*, Docket No. 21-0098, January 2021, June 2021.

Direct Testimony on the cost of equity and capital structure on behalf of Anchorage Water and Wastewater Utility submitted to the *Regulatory Commission of Alaska*, Matters TA168-122 and 168-126, December 2020.

Direct Testimony on the cost of equity on behalf of NW Natural submitted to the *Washington Transportation and Utilities Commission*, Docket No. UG-200994, December 2020.

Written Evidence in Review and Variance of Decision 22570-D01-2018 Stage 2 (AltaGas' capital structure) (joint with Paul R. Carpenter) on behalf of AltaGas Utilities Inc. Filed with the *Alberta Utilities Commission*, Proceeding 25031, January 2020.

Written Evidence on Cost of Equity and Capital Structure on behalf of ATCO, AltaGas and FortisAlberta in 2021-2022 Generic Cost of Capital Proceeding. Filed with the *Alberta Utilities Commission*, Proceeding No. 24110, January 2020.

Report on the Return Margin for the Alberta Bottle Depots on behalf of the Alberta Beverage Container Recycling Corporation, February 2020.

Verified Statement and Reply Verified Statement regarding Revisions to the Board's Methodology for Determining the Railroad Industry's Cost of Capital on behalf of the American Association of Railroads before the *Surface Transportation Board*, Docket No. EP 664 (Sub-No. 4), January, February 2020.

Affidavit regarding the creation of a regulatory asset for earthquake related costs on behalf of Anchorage Water and Wastewater submitted to the *Regulatory Commission of Alaska*, December 2019.

Expert Report and Hearing Appearance on Going Concern and Impairment, *American Arbitration Association*: International Engineering & Construction S.A., Greenville Oil & Gas Co. Ltd and GE Oil & Gas, Inc., November, December 2019.

Direct Testimony and Rebuttal Testimony on the cost of equity on behalf of DTE Gas submitted to the *Michigan Public Service Commission*, Docket No. U-20642, November 2019.

Expert Report on IFRS Issues and Forensics. *SIAC Arbitration* No. 44 of 2018, October 2019.

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Direct Testimony on the cost of debt and equity capital as well as capital structure on behalf of Young Brothers, LLC. submitted to the *Public Utilities Commission of the State of Hawaii*, Docket No. 2019-0117, September 2019.

Direct Testimony on Cost of Equity on behalf of DTE Gas submitted to the *Michigan Public Service Commission*, Docket No. U-20940, February 2021.

Expert Report on discount rates in property tax matter for Union Pacific Company in *Union Pacific Railroad Co. v. Utah State Tax Comm'n, et. al.*, Case No. 2:18-cv-00630-DAK-DBP, Utah August 2019.

Answering Testimony on the Cost of Equity on behalf of Northern Natural Gas Company submitted to the *Federal Energy Regulatory Commission*, Docket No. RP19-59-000, August 2019.

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on Cost of Equity on behalf of DTE Electric Company submitted to the *Michigan Public Service Commission*, Docket No. U-20561, July, November, December 2019.

Prepared Direct Testimony on Cost of Capital for Northern Natural Gas Company submitted to the *Federal Energy Regulatory Commission*, Docket No. RP19-1353-000, July 2019.

Prepared Direct Testimony on Cost of Capital and Term Differentiated Rates for Paiute Pipeline Company submitted to the *Federal Energy Regulatory Commission*, Docket No. RP19-1291-000, May 2019.

Expert report, deposition, and oral trial testimony on behalf of PacifiCorp in the Matter of *PacifiCorp, Inc. v. Utah State Tax Comm'n*, Case No. 180903986 TX, *Utah District Court* April, May, September 2019.

Direct Testimony, Rebuttal Testimony, and hearing appearance on the cost of capital for Southern California Edison submitted to the *California Public Utilities Commission*, Docket No. A.19-04-014, April 2019, August 2019.

Prepared Direct Testimony on the cost of equity for Southern California Edison's transmission assets submitted to the *Federal Energy Regulatory Commission*, Docket No. ER19-1553, April 2019.

Direct and Rebuttal Testimony on cost of equity for Consolidated Edison of New York submitted to the *New York Public Service Commission*, Matter No. 19-00317, January, June 2019.

Direct Testimony on cost of capital and capital structure for Northwest Natural Gas Company submitted to the *Washington Utilities and Transportation Commission*, Docket No. 181053, December 2018.

Pre-filed Direct Testimony and Reply Testimony on cost of capital and capital structure for Anchorage Water Utility and Anchorage Wastewater Utility submitted to the *Regulatory Commission of Alaska*, TA163-122 and TA164-126, December 2018, October 2019.

Direct Testimony on cost of capital for Portland General Electric Company submitted to the *Oregon Public Utility Commission* on behalf of Portland General Electric Company (with Hager and Liddle), UE 335, February 2018.

Direct Testimony and Rebuttal Testimony on cost of capital for NW Natural submitted to the *Oregon Public Utility Commission* on behalf of NW Natural, UG 344, December 2017, May 2018.

Direct Pre-filed Testimony and Reply Pre-filed Testimony on cost of equity and capital structure for Anchorage Water and Wastewater Utilities before the *Regulatory Commission of Alaska*, TA161-122 and TA162-126, November 2017, September 2018.

Direct Testimony, Rebuttal Testimony, deposition, and hearing appearance on wholesale water rates for Petitioner Cities, *Texas Public Utility Commission*, PUC Docket 46662, SOAH Docket 473-17-4964.WS, November 2017, January, June, July, October 2018.

Affidavit on Lifting the Dividend Restriction for Anchorage Water Utility for AWWU, *Regulatory Commission of Alaska*, U-17-095, November 2017.

Written Evidence, Rebuttal Evidence and Hearing appearance on the Cost of Capital and Capital Structure for the ATCO Utilities and AUI, 2018-2020 Generic Cost of Capital Proceeding, *Alberta Utilities Commission*, October 2017, February – March 2018.

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Affidavit on the Creation of a Regulatory Assets for PRV Rebates for Anchorage Water Utility, submitted to the *Regulatory Commission of Alaska*, U-17-083, August 2017.

Direct and Rebuttal Testimony, Hearing Appearance on Cost of Capital for California-American Water Company for California-American Water submitted to the *California Public Utilities Commission*, Application 17-04-003, April, August, September 2017.

Direct, Rebuttal, Surrebuttal, Supplemental, Supplemental Rebuttal Testimony and Hearing Appearance on the Cost of Capital for Northern Illinois Gas Company submitted to the *Illinois Commerce Commission*, GRM #17-055, March, July, August, September, and November 2017.

Direct and Rebuttal Testimony on Cost of Capital for Portland General Electric Company submitted to the *Oregon Public Utility Commission* on behalf of Portland General Electric Company, Docket No. UE 319, February, July 2017.

Pre-filed Direct and Reply Testimony and Hearing Appearance on Cost of Equity and Capital Structure for Anchorage Municipal Light and Power, *Regulatory Commission of Alaska*, Docket No. TA357-121, December 2016, August and December 2017.

Expert report and Hearing Appearance regarding the Common Equity Ratio for OPG's Regulated Generation for OEB Staff, *Ontario Energy Board*, EB-2016-0152, November 2016, April 2017.

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Expert Report, Reply Expert Report and Hearing on damages (quantum) in exit arbitration (with Dan Harris), *International Center for the Settlement of Investment Disputes*, October 2016, October 2018, July 2019.

Direct Testimony on capital structure, embedded cost of debt, and income taxes for Detroit Thermal, Michigan Public Service Commission, Docket No. UE-18131, July 2016.

Direct Testimony on return on equity for Arizona Public Service Company, Arizona Corporation Commission, Docket E-01345A-16-0036, June 2016.

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Verified Statement, Verified Reply Statement, and Hearing Appearance regarding the cost of capital methodology to be applied to freight railroads, the *Surface Transportation Board* on behalf of the Association of American Railroads, Docket No. EP 664 (Sub-No. 2), July 2015, September and November 2015.

Direct Testimony on cost of capital submitted to the Oregon Public Utility Commission on behalf of Portland General Electric, Docket No. UE 294, February 2015.

Supplemental Direct Testimony and Reply Testimony on cost of capital submitted to the *Regulatory Commission of Alaska* on behalf of Anchorage Water and Wastewater utilities, Docket U-13-202, September 2014, March 2015.

Expert Report and hearing appearance on specific accrual and cash flow items in a Sales and Purchase Agreement in international arbitration before the *International Chamber of Commerce*. Case No. 19651/TO, July and November 2014. (*Confidential*)

Rebuttal Testimony regarding Cost of Capital before the *Oregon Public Utility Commission* on behalf of Portland General Electric, Docket No. UE 283, July 2014.

Direct Testimony on the rate impact of the pension re-allocation and other items for Upper Peninsula Power Company in connection with the acquisition by BBIP before the *Michigan Public Service Commission* in Docket No. U-17564, March 2014.

Expert Report on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of oil pipeline in arbitration, April 2013. (with A. Lawrence Kolbe, Michael J. Vilbert, *Confidential*)

Direct Testimony on the treatment of goodwill before the *Federal Energy Regulatory Commission* on behalf of ITC Holdings Corp and ITC Midwest, LLC in Docket No. PA10-13-000, February 2012.

Direct and Rebuttal Testimony on cost of capital before the *Public Utilities Commission of the State of California* on behalf of California-American Water in Application No. 11-05, May 2011.

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Case No. 11-00196-UT, May 2011, November 2011, and December 2011.

Direct Testimony on regulatory assets and FERC accounting before the *Federal Energy Regulatory Commission* on behalf of AWC Companies, EL11-13-000, December 2010.

Expert Report and deposition in Civil Action No. 02-618 (GK/JMF) in the *United States District Court for the District of Columbia*, November 2010, January 2011. (*Confidential*)

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Expert Report on accounting information needed to assess income. *United States District Court* for the District of Maryland (Baltimore Division), Civil No. 1:06cv02046-JFM, June 2007 (*Confidential*)

Expert Report, Rebuttal Expert Report, and Hearing Appearance regarding investing activities, impairment of assets, leases, shareholder' equity under U.S. GAAP and valuation. *International Chamber of Commerce* (ICC), Case No. 14144/CCO, May 2007, August 2007, September 2007. (Joint with Carlos Lapuerta, *Confidential*)

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0491, July 2006, July 2007.

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Expert report, rebuttal expert report, and deposition on behalf of a major oil company regarding the equity method of accounting and classification of debt and equity, *American Arbitration Association*, August 2004 and November 2004. (*Confidential*).

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Amber Riter

July 9, 2021

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I. Introduction and Summary

Q. Please state your name and position 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. I am responsible for developing PGE's energy deliveries forecast. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. This testimony presents PGE's 2022 test year energy and customer forecast[1].

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 the approach described in this testimony to account for shifts in usage associated with the COVID-19 pandemic; 2) accept, as a preliminary matter, our forecast of energy deliveries, recognizing that important updates will be made throughout the course of this proceeding, and 3) set a schedule in this proceeding allowing for periodic updates of the energy delivery forecast for 2022.

Q. How has the COVID-19 pandemic impacted PGE's load forecast?

A. The COVID-19 pandemic has significantly altered the way PGE's customers use electricity. Uncertainty with respect to the path of the virus and what the 'new-normal' looks like increases the uncertainty of PGE's load forecast. This structural change in PGE's time series historical energy deliveries data requires model intervention to estimate PGE's energy deliveries forecast, which will be described in this testimony.

Q. Does PGE intend to update its 2022 forecast during this case?

[1] The terms "energy deliveries" and "load forecast" are used interchangeably in this testimony

A. Yes, PGE performs load forecast updates multiple times each year to incorporate new data as 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 input assumptions and the economic outlook for Oregon; and 3) incorporate the most current operational information in large customers' usage forecasts.

Q. At what cadence does PGE intend to update its 2022 forecast during this case?

A. PGE's load forecast 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 March 2021 load forecast. PGE did not update its load forecast in June of 2021 given no significant change to input assumptions and intends to next update its load forecast in September of 2021.

Q. Please describe PGE's delivery forecast.

A. PGE's 2022 test year energy forecast is for energy deliveries of 20,497 thousand megawatt--hours (MWh), 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 2022, as well as operational changes among PGE's largest customers and savings from incremental energy efficiency (EE) programs that are implemented by the Energy Trust of Oregon (ETO).

Q. How does the 2022 forecast compare to recent historical demand?

A. Similar to the energy delivery trends of recent years, the 2022 forecast reflects strong growth in energy deliveries to industrial customers (primary voltage service). Industrial deliveries growth is related to high-tech expansion and new data centers. The rate of growth in deliveries to industrial customers has increased in recent years following large high-tech construction projects. For the Residential and General Service classes, we expect those trends driving deliveries prior to 2020 will continue to influence the forecast. However, 2022 growth rates reflect the unwinding of the impacts of COVID-19 on energy deliveries in 2021.

Table 1, below, summarizes the MWh delivery forecast in annual percentage changes by voltage service customer class on a weather adjusted, billing cycle basis from 2018 through 2022.

Table 1
Percent Change in MWh Delivery from Preceding Year: 2018-2022

Voltage Service Class	2018	2019	2020	2021 (E)	2022 (E)
Residential	0.8%	-2.0%	4.9%	1.1%	-3.7%
General Service[2]	0.2%	-1.5%	-6.8%	2.1%	3.1%
Transmission	-31.2%	2.0%	10.5%	2.9%	-1.3%
Primary	4.2%	6.9%	6.3%	7.6%	9.3%
Total	0.6%	0.1%	0.8%	3.0%	1.9%

Q. How has PGE's load forecast performed compared to industry standard?

A. While forecasts are always subject to uncertainty, PGE's load forecast has performed very well over the years. Table 2 displays PGE's load forecast variance, compared to industry averages, measured in mean absolute percentage error (MAPE), as reported in Itron's annual load forecasting benchmark survey.

Table 2
Comparison of PGE Forecast Error to Itron Benchmark Survey

	2014		2015		2016		2017		2018		2019	
	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE
Residential	1.5%	1.2%	1.9%	1.5%	1.7%	0.1%	1.4%	-1.3%	1.8%	-0.5%	1.2%	-2.2%
Commercial	1.3%	0.6%	1.6%	0.8%	1.8%	-2.0%	1.3%	0.3%	2.0%	1.1%	1.7%	-1.0%
Industrial	3.4%	-0.5%	3.0%	2.8%	3.3%	-2.7%	2.3%	2.0%	1.9%	0.7%	4.1%	4.8%
System	1.3%	0.6%	1.9%	1.5%	1.6%	-1.4%	1.1%	0.0%	1.3%	0.4%	1.4%	-0.2%

[2] General Service is the summation of Secondary Voltage and Miscellaneous Schedules.

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 regression models which estimate energy deliveries' relationship to 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.

Q. How are customers grouped in the forecast models?

A. The forecast (of MWh deliveries) is estimated for residential, commercial, manufacturing customers and energy served under miscellaneous rate schedules. For residential customers, we model both customer counts and usage per customer for seven segments based on dwelling type and space heating type.

Non-residential customers are separated into eleven commercial and seven manufacturing groups based on the North America Industrial Classification System (NAICS)[3].

Q. How do you forecast the gross loads delivered to the PGE system?

A. The process of converting metered energy deliveries to gross loads involves three steps: 1) aggregated cycle-based NAICS sector 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; and 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. For the 2022 test year, we apply line loss factors beginning in 2021 as presented in Exhibit 1200.

Q. Are these models new or different from previous PGE energy delivery models?

[3] https://www.census.gov/eos/www/naics/

A. The forecast models and process remain fundamentally the same as those used in previous filings with the Commission. However, there are some updates in model specifications, specifically with respect to reexamination of the underlying structure of historical data series, impact of COVID-19, and relationships to weather and economic drivers.

Q. What sources of information do you use to forecast electricity deliveries?

A. PGE primarily relies on its own historical billing data to forecast energy deliveries. In addition, the forecast of economic drivers comes from the Oregon Department of Administrative Services' Office of Economic Analysis (OEA). Historical weather data comes from the National Oceanic and Atmospheric Administration (NOAA). Energy efficiency data comes from the ETO. In addition, customers who are large energy users provide us with specific operational information, direct inputs and, if available, forecasts of energy use through correspondence with PGE's Key Customer Managers.

Q. How current are the data you use to estimate the model?

A. The models estimated for use in this proceeding are based on energy data through the January 2021 billing cycle and customer connects data through September 2020. OEA's March 2021 economic forecast was used to develop the forecast for this proceeding.

Q. What assumption did you make regarding weather variables in the forecast?

A. The test-year forecast is based on a modeled normal weather assumption, which uses a trend 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 2019. The structure of the model estimates a linear trend fit beginning in 1975. This methodology was approved by the commission in UE 335. Exhibit 1011 shows the degree days used for 2021 and 2022.

III. COVID-19

Q. What impact has COVID-19 had on PGE's energy deliveries?

A. COVID-19 has shifted energy usage in several ways. Residential customers are spending more time at home, reflecting school closures, and increased work-from-home. As such, deliveries to the residential segment have increased. Commercial segments largely reflect an opposite impact. As forced closures demanded that operations be reduced or stopped altogether, many commercial customers decreased usage. Lodging, Restaurants and Government and Education have seen some of the largest decreases, consistent with economic impacts. Manufacturing segment deliveries were largely customer specific and not consistent across groups, as demand in some areas continued to grow and others deteriorated. Segment level year over year energy deliveries trends can been seen in Exhibit 1006 and 1007.

Q. What changes have been made to model specifications to account for COVID-19?

A. Binary control variables have been introduced to PGE's forecasting models to reflect the shock imposed by the COVID-19 crisis. Three specific variables were found to be the most useful in the model specifications. For the commercial models, use of two variables, each reflecting one of two distinct phases of COVID-19 related shutdowns, performed well. For residential models, the phased re-opening seemed to have little impact, so a single variable was used to reflect the entire period. This is consistent with the idea that most who have been able to work from home have continued to do so throughout 2020 and schools remain largely virtual, despite changes in COVID shutdown policies.

Q. What assumptions did you make regarding the progression of the COVID-19 pandemic?

A. PGE has accounted for the impact of COVID-19 on energy deliveries in its regression models by using a set of indicator variables reflecting different levels of stay-at-home policy measures in PGE's service area. In the forecast period, specific assumptions must be made to reflect the future conditions of these variables. PGE has accounted for future conditions in two primary ways. First, by extending the indicator variables reflecting stay-home policies into the forecast period. The March 2021 forecast assumes that there will be no stay-home policies implemented in 2022. In 2021, stay home policies are in place through the end of August. The variables used are included in Exhibit 1012.

Q. Are any additional assumptions made regarding the impacts of COVID-19?

A. Yes. While there is significant uncertainty surrounding what a 'new normal' looks like, based on announcements from regional employers, we expect to see a sustained uptick in work from home following the pandemic. In addition to the policy-based assumptions described above, we include an input assumption that 1/3 (or 33%) of the estimated increase in residential usage related to COVID-19 will continue in perpetuity.

IV. Energy Efficiency

Q. Did you make any adjustments for incremental energy efficiency to the forecast?

A. Yes. We adjusted the forecast to account for the impact of PGE's incremental EE programs funded through Schedule 109 Incremental EE Funding, enabled by Senate Bill 838 (SB 838), as forecasted by the ETO in January of 2021. Since EE trends, including SB 1149[4] measures, are assumed to be captured implicitly in the forecast model, no explicit adjustments are made for SB 1149 savings.

Q. Has PGE made any changes to its energy efficiency adjustment since UE 335?

A. No. PGE has not changed its approach to the EE adjustment. In UE 319, Staff raised concern with the incremental versus embedded nature of SB 838 savings. In UE 335, Staff brought up a similar concern and, in settlement, PGE agreed to reducing the adjustment by 40% for the 2019 test year forecast. However, PGE's residential and commercial energy deliveries, those segments most impacted by EE, were below forecast in 2019, by 2.2% and 1.0% respectively, as shown in Exhibit 1013. While the negotiated energy efficiency adjustment is not responsible for the entirety of model error, PGE's forecast would have performed better had it not agreed to this adjustment.

PGE recognizes that as time passes since the enactment of SB 838 in 2007, the level of embedded savings becomes less clear. While PGE is interested in investigating alternative approaches, at this time we believe our current adjustment mechanism performs well and is both appropriate and necessary for the development of PGE's energy deliveries forecast.

Q. What is the impact of incremental EE programs savings on the forecast?

[4] Oregon Senate Bill 1149 established the 3% public purpose charge to fund and encourage energy conservation.

A. We estimate a total of 159.3 thousand MWh or 0.8% savings from these programs in the 2022 test year based on the EE savings starting in February 2021 and accumulating through December 2022. Refer to PGE Exhibits 1001-1003 to see the impact of the energy efficiency adjustment on PGE's energy deliveries forecast.

Q. How does PGE account for the impact of other distributed energy resources (DER's) in its forecast?

A. PGE's near-term energy deliveries forecast does not directly account for the interactive impact of other distributed energy resources. As the saturation of these resources grows, it will be important to consider how DER's will impact near term energy deliveries and be accounted for in PGE's load forecast model. PGE is currently conducting analysis to support Docket No. UM 2005 focused on distribution system planning which will be used to guide integration of additional DER impacts into the near-term load forecast.

V. Forecast Results

Q. What are the key results of PGE's residential sector forecast?

A. For the 2022 test year, we forecast deliveries of 7,555 thousand MWh to 809,036 residential customers. Declines in residential use per customer, driven by the reversal of COVID-19 related impacts and incremental energy efficiency programs, are partially offset by customer growth of 1.0% in 2022, for annual residential energy deliveries decrease of -3.7% over 2021. PGE Exhibit 1004 shows the forecast of building permits, new connects, and customer counts. PGE Exhibit 1005 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 sector forecast?

A. For the 2022 test year, we forecast deliveries of 6,788 thousand MWh to NAICS-based commercial customers, a 3.6% increase over forecasted 2021 energy deliveries. Increases in energy deliveries to the commercial NAICS groups reflect reopening of commercial operations, partially offset by savings from incremental EE programs. PGE Exhibit 1006 contains the detailed forecast of deliveries to commercial customers.

Q. What are the key results of PGE's manufacturing sector forecast?

A. For test year 2022, we forecast deliveries of 6,104 thousand MWh to NAICS-based manufacturing customers, 7.9% higher than forecasted 2021 deliveries, following growth of 7.3% in 2021 and 4.9% in 2020. The manufacturing forecast reflects continued expansion by high-tech and related companies in PGE's service territory. PGE Exhibit 1007 presents the detailed delivery forecast of the manufacturing sector.

Q. What are the key results of PGE's miscellaneous rate schedules forecast?

A. Deliveries to miscellaneous rate schedules account for a very small portions of total retail deliveries. PGE Exhibit 1008 displays the miscellaneous schedules' forecast.

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 2020 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 2022. We prorate the COS and Schedule 485/489 deliveries by applying these customers' respective historical shares of service level or revenue class 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 1010 shows the forecast of deliveries in 2022 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 is our "expected" or mid-point estimate but is subject to uncertainty. As such, it is a 50/50 "point" forecast, 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 the model, the independent variables include assumptions about the path of the COVID-19 pandemic and long-term response to work from home, weather variables and the economic forecast drivers. In addition, the model includes assumptions surrounding implementation of EE programs, 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 its 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 its forecast multiple times in any given year, as described earlier in this testimony, to include the most recent historical trends, billing data, and input assumptions available. PGE expects to include an updated load forecast as the final forecast for setting 2022 rates in this proceeding.

VII. Qualifications

Q. Ms. Riter, please describe your qualifications.

A. I received my Bachelor of Arts in Economics from New Mexico State University and my Master of Arts in Economics, specializing in Environmental and Natural Resource Economics, from The University of New Mexico. I have been working as an Economist in energy deliveries forecasting for the past 11 years. Prior to joining PGE in 2014, I worked at PNM Resources, the parent company of Public Service Company of New Mexico and Texas-New Mexico Power, performing load forecasting and load research analysis. I have attended conferences and delivered presentations to regional and national utility load forecasting groups including the Pacific Northwest Utilities Conference Committee Load Forecasting subgroup and the Edison Electric Institute Load Forecasting Working Group. I also participated in a Forecast Assumptions Working Group to support the Hawaiian Electric Integrated Grid Planning process which kicked off in early 2019.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
1001	Energy Deliveries Forecast, Base
1002	Energy Deliveries Forecast, Final
1003	Energy Efficiency Adjustment
1004	New Connects
1005	Residential Usage
1006	Commercial NAICS Groups
1007	Manufacturing NAICS Groups
1008	Miscellaneous MWh
1009	Total Net System Deliveries
1010	Split between Cost-of-Service and Direct Access
1011	Degree Days for 2021-2022
1012	COVID-19 Control Variables
1013	Forecast Accuracy

Energy Deliveries Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (not adjusted) Forecast [1]

	(in thousand MWh)					% Change [2]				
	2018	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Schedule 7	7,554	7,402	7,764	7,856	7,591	0.8%	-2.0%	4.9%	1.2%	-3.4%
Residential Lighting	2	2	2	2	2	-29.4%	-23.4%	-1.1%	-2.9%	0.0%
Total Residential	7,557	7,404	7,765	7,857	7,592	0.8%	-2.0%	4.9%	1.2%	-3.4%
Commercial [3]	6,909	6,867	6,431	6,567	6,853	0.2%	-0.6%	-6.4%	2.1%	4.4%
Manufacturing [3]	4,718	4,956	5,198	5,590	6,073	1.0%	5.0%	4.9%	7.5%	8.6%
Miscellaneous Customers	160	141	135	141	138	2.8%	-11.6%	-4.5%	4.3%	-1.8%
Secondary Voltage	7,410	7,304	6,804	6,977	7,273	0.4%	-1.4%	-6.8%	2.5%	4.2%
Total General Service	7,465	7,356	6,856	7,024	7,317	0.2%	-1.5%	-6.8%	2.4%	4.2%
Primary Voltage Service	4,062	4,343	4,615	4,973	5,449	4.2%	6.9%	6.3%	7.7%	9.6%
Transmission Voltage Service	260	265	293	301	298	-31.2%	2.0%	10.5%	2.9%	-1.3%
Total Retail [4]	19,344	19,368	19,529	20,156	20,657	0.6%	0.1%	0.8%	3.2%	2.5%

1 MAR21B_W75

2 Calculated from rounded numbers

3 By NAICS grouping

4 Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

Energy Deliveries Forecast (Energy Efficiency Adjusted) by Market Segment and Service Level

(at average weather)

Net of Incremental Energy Efficiency [1]

	(in thousand MWh)					% Change [2]				
	2018	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Schedule 7	7,554	7,402	7,764	7,846	7,555	0.8%	-2.0%	4.9%	1.1%	-3.7%
Residential Lighting	2	2	2	2	2	-29.4%	-23.4%	-1.1%	-0.6%	-1.1%
Total Residential	7,557	7,404	7,765	7,847	7,557	0.8%	-2.0%	4.9%	1.1%	-3.7%
Commercial [3]	6,909	6,867	6,431	6,551	6,788	0.2%	-0.6%	-6.4%	1.9%	3.6%
Manufacturing [3]	4,718	4,956	5,198	5,575	6,014	1.0%	5.0%	4.9%	7.3%	7.9%
Miscellaneous Customers	160	141	135	141	139	2.8%	-11.6%	-4.5%	4.7%	-1.8%
Secondary Voltage	7,410	7,304	6,804	6,952	7,169	0.4%	-1.4%	-6.8%	2.2%	3.1%
Total General Service	7,465	7,356	6,856	6,999	7,213	0.2%	-1.5%	-6.8%	2.1%	3.1%
Primary Voltage Service	4,062	4,343	4,615	4,968	5,430	4.2%	6.9%	6.3%	7.6%	9.3%
Transmission Voltage Service	260	265	293	301	298	-31.2%	2.0%	10.5%	2.9%	-1.3%
Total Retail [4]	19,344	19,368	19,529	20,115	20,497	0.6%	0.1%	0.8%	3.0%	1.9%

1 SMAR21E_W75

2 Calculated from rounded numbers

3 By NAICS grouping

4 Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

Forecast of Incremental Energy Efficiency (EE) Savings

(in thousand MWh)

	2021	2022
Base (B) Forecast	20,156	20,657
Incremental EE Savings [1]	(41)	(159)
Post-EE Forecast (E) [2]	20,115	20,497

1 Energy Trust of Oregon (ETO) annual savings deployment forecast.

2 Totals and differences may not foot due to rounding.

Residential Building Permits, New Connects, Vacancy Rates and Customer Counts History and Forecast

	2018	2019	2020 [1]	2021 [1]	2022
Building Permits [2]					
Single-Family	10,333	10,087	10,480	10,060	11,108
Multi-Family	9,096	10,756	6,932	8,016	9,592
New Connects					
Single-Family	4,902	4,908	4,531	4,721	4,733
Multi-Family	6,163	5,430	6,085	4,688	4,177
Mobile Home	115	123	121	120	120
Other	175	233	262	180	180
Total Residential Connects	11,355	10,694	10,999	9,709	9,210
Commercial Connects	2,785	2,619	2,300	2,211	2,390
Total New Connects	14,140	13,313	13,299	11,920	11,600
Residential Customer Counts					
Single-Family Heat	114,390	116,928	119,127	121,374	121,964
Single-Family Non-Heat	367,333	368,674	371,545	373,583	377,030
Multiple-Family Heat	192,248	197,323	203,820	209,178	211,635
Multiple-Family Non-Heat	61,042	60,172	59,723	60,004	61,215
Mobile Home Heat	30,738	30,655	30,712	30,700	30,583
Mobile Home Non-Heat	4,099	4,170	4,199	4,206	4,200
Other	2,625	1,750	2,028	2,331	2,409
Total Number of Accounts [3]	772,423	779,673	791,154	801,374	809,036

1) Includes actuals through January 2021, except for connects which include actuals through Septmeber 2020

2) Oregon building permits

3) Includes vacant accounts

Forecast of Residential Use per Customer and Ultimate Deliveries

(at average weather)

Net of Incremental Energy Efficiency

	2018	2019	2020	2021	2022
Use per Customer (kWh)					
Single-Family Heat	14,169	13,622	13,993	13,975	13,425
Single-Family Non-Heat	9,746	9,564	9,982	9,959	9,447
Multiple-Family Heat	7,821	7,469	7,643	7,607	7,285
Multiple-Family Non-Heat	5,880	5,732	5,958	5,973	5,716
Mobile Home Heat	13,670	13,260	13,391	13,522	13,235
Mobile Home Non-Heat	10,765	10,703	10,918	11,031	10,654
Other	10,175	7,429	8,392	7,591	6,127
Average Use per Customer	9,783	9,496	9,815	9,792	9,340
Ultimate Deliveries (millions of kWh)					
Single-Family Heat	1,621	1,593	1,667	1,696	1,637
Single-Family Non-Heat	3,580	3,526	3,709	3,721	3,562
Multiple-Family Heat	1,504	1,474	1,558	1,591	1,542
Multiple-Family Non-Heat	359	345	356	358	350
Mobile Home Heat	420	406	411	415	405
Mobile Home Non-Heat	44	45	46	46	45
Other	27	13	17	18	15
Schedule 7 Deliveries	7,555	7,402	7,764	7,845	7,555
Residential Lighting	2	2	2	2	2
Total Residential Deliveries	7,557	7,404	7,766	7,847	7,557

Commercial Energy Deliveries Forecast by NAICS Sector

(at average weather)

Net of Incremental Energy Efficiency

						% Change [1]				
	2018 [2]	2019 [2]	2020 [2]	2021	2022	2018	2019	2020	2021	2022
Food Stores	415	397	371	373	370	-1.5%	-4.3%	-6.6%	0.7%	-0.7%
Govt. & Education	983	963	843	875	950	-0.1%	-2.0%	-12.4%	3.7%	8.5%
Health Services	715	730	708	714	718	-0.5%	2.1%	-3.0%	0.7%	0.6%
Lodging	107	104	87	90	99	0.9%	-2.9%	-16.4%	3.7%	10.0%
Misc. Commercial	634	582	609	596	586	-11.0%	-8.2%	4.7%	-2.2%	-1.6%
Department Stores/Malls	316	302	283	290	307	-5.0%	-4.4%	-6.3%	2.6%	5.7%
Office & F.I.R.E. [3]	1,068	1,118	1,050	1,078	1,110	12.0%	4.6%	-6.1%	2.6%	3.0%
Other Services	847	857	771	788	847	0.2%	1.3%	-10.1%	2.3%	7.4%
Other Trade	724	725	700	713	717	1.4%	0.2%	-3.5%	1.9%	0.6%
Restaurants	475	465	393	409	464	-1.1%	-2.2%	-15.5%	4.2%	13.3%
Trans., Comm. & Utility	627	624	616	625	620	-0.4%	-0.4%	-1.2%	1.4%	-0.8%
Total Commercial	6,909	6,867	6,431	6,551	6,788	0.2%	-0.6%	-6.4%	1.9%	3.6%

1 Calculated using rounded-numbers

2 Weather-adjusted

3 Finance, Insurance, and Real Estate

Manufacturing Deliveries Forecast by NAICS Sector

(at average weather)

Net of Incremental Energy Efficiency

								% Change [1]		
	2018 [2]	2019 [2]	2020 [2]	2021	2022	2018	2019	2020	2021	2022
Food & Kindred Products	273	274	275	265	258	2.0%	0.1%	0.4%	-3.5%	-2.8%
High Tech	2,771	3,008	3,343	3,695	4,137	6.0%	8.5%	11.1%	10.5%	11.9%
Lumber & Wood	101	96	88	90	88	0.4%	-5.5%	-8.2%	3.1%	-3.0%
Metal Manufacturing and Fab	445	445	388	383	385	-0.1%	0.0%	-12.9%	-1.3%	0.5%
Other Manufacturing	780	778	731	761	769	1.6%	-0.2%	-6.1%	4.2%	1.0%
Paper Manufacturing	174	180	218	228	221	-41.2%	3.2%	21.3%	4.6%	-3.2%
Transportation Equipment	173	176	156	152	156	-2.7%	1.5%	-11.0%	-2.8%	2.9%
Total Manufacturing	4,718	4,956	5,198	5,575	6,014	1.0%	5.0%	4.9%	7.3%	7.9%

1 Calculated using rounded-numbers

2 Weather-adjusted

Forecast of Energy Deliveries to Miscellaneous Rate Schedules

Net of Incremental Energy Efficiency

	(in thousand MWh)					% Change [1]				
	2018	2019	2020	2021 [2]	2022 [2]	2018	2019	2020	2021	2022
Residential										
Outdoor Area Lighting (15R) [3]	2	2	2	2	2	-29.4%	-22.9%	-1.7%	-1.1%	-1.2%
Secondary (Commercial)										
Outdoor Area Lighting (15C) [4]	14	14	13	13	13	5.0%	1.0%	-4.0%	-2.8%	0.0%
Farm Irrigation et al. [5]	91	76	70	81	82	15.0%	-16.8%	-7.7%	16.3%	0.1%
Street and Other Lighting [6]	55	52	52	47	44	-12.9%	-6.1%	0.1%	-9.1%	-5.7%
Total Miscellaneous Commercial	160	141	135	141	139	2.8%	-11.6%	-4.5%	4.7%	-1.8%
All Miscellaneous Schedules [7]	162	143	137	143	140	2.1%	-11.8%	-4.4%	4.6%	-1.8%

1 Calculated from rounded numbers

2 Identical for non-price, price-effect and post-EE forecasts

3 Existing Schedule 15R

4 Existing Schedule 15C

5 Existing Schedules 47 & 49

6 Existing Schedules 91, 92 & 93, and Schedule 95 beginning in 2013. Rate schedule 93 moved to Rate Schedule 38 in 2014.

7 Equals line 2 + line 7

Total Delivery and Demand Forecast

Net of Incremental Energy Efficiency [4]

	Million kWh [1]	Average MW [2]	Peak MW [3]
2013	19,265	2,346	3,869
2014	19,420	2,329	3,866
2015	19,344	2,344	3,914
2016	19,368	2,287	3,726
2017	19,529	2,389	3,976
2018	19,398	2,322	3,816
2019	19,367	2,343	3,765
2020	19,529	2,348	3,771
2021	20,115	2,436	3,824
2022	20,497	2,483	3,877

1 Cycle-month basis, at end-user meters, weather adjusted; includes actual deliveries through Jan 2021

2 Calendar basis, at the bus bar, actual through Jan 2021, not adjusted for weather.

3 Coincidental annual system peak at bus bar; includes actual through Jan 2021, not adjusted for weather.

4 2021 and 2022 are the incremental EE adjusted forecast.

Forecast of 2022 Deliveries to Cost of Service and Direct Access Customers

Net of Incremental Energy Efficiency

(in thousand MWh)

	Cost of Service [1]	Direct Access [2]	Total Delivery [3]
Residential	7,557	0	7,557
Secondary	6,637	532	7,169
Primary	4,000	1,430	5,430
Transmission	54	244	298
Lighting	44	0	44
Total Retail [3]	18,291	2,206	20,497

1 Includes economic replacement VPO deliveries

2 Schedule 485/489/689 deliveries

3 Totals may not add due to rounding.

Degree Day Variables

	2021		2022	
	HDD65	CDD65	HDD65	CDD65
January	763.0	0.0	761.5	0.0
February	648.7	0.0	647.6	0.0
March	546.0	0.0	545.1	0.0
April	396.4	0.4	394.9	0.4
May	241.1	12.2	239.5	12.3
June	113.7	43.0	112.4	43.5
July	37.8	137.8	37.5	139.1
August	9.5	216.6	9.5	218.8
September	26.4	161.4	26.1	163.2
October	134.8	31.8	133.6	32.1
November	365.5	0.3	364.2	0.3
December	665.1	0.0	664.3	0.0
Annual	3,948.0	603.4	3,936.2	609.7

Cycle Weighted COVID-19 Variables

		Residential	Non-Residential	
Year	Month	Variable 1	Phase 1	Phase 2
2020	1	0.0	0.0	0.0
2020	2	0.0	0.0	0.0
2020	3	0.2	0.1	0.2
2020	4	0.9	0.8	0.2
2020	5	1.0	1.0	0.0
2020	6	1.0	0.9	0.1
2020	7	1.0	0.2	0.8
2020	8	1.0	0.0	1.0
2020	9	1.0	0.0	1.0
2020	10	1.0	0.0	1.0
2020	11	1.0	0.0	1.0
2020	12	1.0	0.0	1.0
2021	1	1.0	0.0	1.0
2021	2	1.0	0.0	1.0
2021	3	1.0	0.0	1.0
2021	4	1.0	0.0	1.0
2021	5	1.0	0.0	1.0
2021	6	1.0	0.0	1.0
2021	7	1.0	0.0	1.0
2021	8	1.0	0.0	1.0
2021	9	0.5	0.0	0.5
2021	10	0.3	0.0	0.0
2021	11	0.3	0.0	0.0
2021	12	0.3	0.0	0.0
2022	1	0.3	0.0	0.0
2022	2	0.3	0.0	0.0
2022	3	0.3	0.0	0.0
2022	4	0.3	0.0	0.0
2022	5	0.3	0.0	0.0
2022	6	0.3	0.0	0.0
2022	7	0.3	0.0	0.0
2022	8	0.3	0.0	0.0
2022	9	0.3	0.0	0.0
2022	10	0.3	0.0	0.0
2022	11	0.3	0.0	0.0
2022	12	0.3	0.0	0.0

Comparison of PGE Forecast Error to Itron Benchmarking Survey

	2011		2012		2013		2014		2015		2016		2017		2018		2019	
	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE
Residential	1.7%	-0.5%	1.5%	0.0%	1.7%	0.3%	1.5%	1.2%	1.9%	1.5%	1.7%	0.1%	1.4%	-1.3%	1.8%	-0.5%	1.2%	-2.2%
Commercial	1.7%	-0.4%	2.0%	-1.4%	2.1%	-1.9%	1.3%	0.6%	1.6%	0.8%	1.8%	-2.0%	1.3%	0.3%	2.0%	1.1%	1.7%	-1.0%
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%	2.3%	2.0%	1.9%	0.7%	4.1%	4.8%
System	NA	-0.5%	1.6%	-1.5%	1.5%	-2.5%	1.3%	0.6%	1.9%	1.5%	1.6%	-1.4%	1.1%	0.0%	1.3%	0.4%	1.4%	-0.2%

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Robert Macfarlane
Christopher Pleasant

July 9, 2021

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 for Portland General Electric Company (PGE). I am responsible, along with Mr. Pleasant, for the development of the marginal cost studies.

My name is Christopher Pleasant. I am a Senior Regulatory Analyst in Pricing and Tariffs for 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 1101 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 discussed in PGE Exhibit 1201.

Q. What is the purpose of the distribution and customer marginal cost studies?

A. The purpose is to calculate the incremental or marginal unit cost of service for various categories (e.g., 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 1200.

II. Generation Marginal Cost Study

Q. What methodology do you propose in this docket?

A. We propose a long-run generation methodology that explicitly takes into account the cost of marginal generation capacity, long-run marginal energy costs, and renewable energy requirements.

Q. Please describe the steps used to develop the long-run generation allocation methodology.

A. The generation marginal cost analysis involves the following inputs and steps:

1. Determine both a long-run marginal energy cost and a long-run marginal capacity cost by first defining the marginal long-run generation resource as a combined cycle combustion turbine (CCCT) used to provide both energy and capacity.
2. From this analysis, separately estimate the capacity and energy components as follows:
    a. Estimate the marginal cost of future capacity as the fixed cost of an “F-class” simple cycle combustion turbine (SCCT).
    b. Use these SCCT fixed costs as the portion of the CCCT fixed cost that is assigned to capacity with the remaining CCCT fixed costs assigned to energy.
    c. Add 12% reserve requirements to the SCCT capacity costs consistent with UE 335.
3. Finally, express the capacity and energy values in real levelized terms.

Q. Has the methodology used to develop the long-run generation allocation changed since PGE’s 2019 General Rate Case filed as Docket No. UE 335?

A. No.

Q. What are the sources of the overnight capital costs for the resources used in the model?

A. PGE's 2019 IRP is the source of the overnight capital costs[1] used in the analysis.

Q. Please describe how you determined the proportion of marginal energy costs attributable to the CCCT and the generic wind farm.

A. We weighted the marginal energy cost by the Renewable Portfolio Standard target percentages for each year. For example, if the RPS target is 20% in a given year, the weighting is 20% wind and 80% thermal. The weightings reflect the revised RPS targets included in Senate Bill 1547.[2]

Q. What is the source of your long-term gas price forecast?

A. We used the 2020 H2 Wood Mackenzie long-term gas price forecast for the Sumas and AECO hubs, blended with near-term forward curves. We equally weighted the projected burner tip prices from these two hubs.

Q. Did you include the projected costs of carbon dioxide compliance in your analysis?

A. No. On both the national and state level, no carbon tax exists. Any potential future carbon tax is uncertain. The exclusion of carbon tax from this analysis is consistent with the treatment of carbon tax for purposes of PGE's avoided cost calculations used in Schedule 201.

Q. Did you include production tax credits in your analysis?

A. Yes. A production tax credit value of 60% was used.

Q. What is the fully allocated cost of the wind farm?

A. The cost of the generic wind plant exclusive of wheeling is estimated at $42.05 per megawatt hour (MWh) in real levelized 2019 dollars.

Q. How did you estimate each rate schedule's long-run marginal cost of energy?

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[1] Cost of the project as if no interest were included during its construction.
[2] 78th Oregon Legislative Assembly, 2016 Regular Session

A. We multiply each schedule's monthly on-peak and off-peak load forecast by the corresponding monthly on-peak and off-peak long-term energy value.

Q. How do you shape the annual long-run marginal cost of energy into monthly on-peak and off-peak values?

A. 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 391 - 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 as that used in UE 335. Based on the transmission projects and transmission substation marginal costs, contained in PGE Exhibit 1102, we calculate a unit marginal cost of $55.93kW.[4]

Q. Why did transmission unit marginal costs see such a significant increase compared to the transmission unit marginal costs in UE 335?

A. Transmission unit marginal costs increased compared to the transmission unit marginal costs in UE 335 because 115 kilovolts (kV) which were previously classified as a distribution asset have been reclassified to the transmission system. As such, $37 Million which was previously in Distribution FERC Account 364, Poles & Towers has moved to Transmission FERC Account 355 and $61 Million which was previously in Distribution FERC Account 365 Overhead Conductors has moved to Transmission FERC Account 356.

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 is 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.

[4] The transmission marginal cost value is shown in the provided transmission marginal cost study.

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 on the basis of 1-in-3 peak load conditions during the summer and winter seasons for both the near term and the long-term.[5] The winter period is defined as November 1st through March 31st, and the summer is defined as June 1st through October 31st, therefore ten months in all. Because 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 criteria, or twelve coincident peak (12CP) is also consistent with how the Federal Energy Regulatory Commission (FERC) determines PGE's Open Access Transmission Tariff prices.

[5] Ibid, page 6.

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-year period between 2017-2022. We then annualize these capital expenditures and divide 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. Customers served at subtransmission voltage are excluded from this calculation because they supply their own substation. Columns (B) and (C) in PGE Exhibit 1101, page 3, summarize 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 generally 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 into 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), (E), and (F) on page 3 of PGE Exhibit 1101 summarize feeder mainline and tapline costs.

Q. Why do you propose to calculate the marginal costs of feeders on the basis of 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 the 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 in 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 $6.1 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 $60,000 in transformer costs from overhead and underground line maintenance to the transformer maintenance account.

Column (F) on page 3 of PGE Exhibit 1101 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 in order to appropriately calculate the per customer share of transformer costs. Column (G) on page 3 of PGE Exhibit 1101 summarizes transformer and service costs.

Because primary and subtransmission voltage customers supply their own transformer 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 1101 summarizes meter costs.

Q. How do you allocate distribution operations and maintenance (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 1101, are inclusive of test-period distribution O&M.

Q. Why did PGE split out the Distribution Marginal Costs for Residential Single-Family and Residential Multi-Family in its Distribution Marginal Cost Study?

A. PGE split out the Distribution Marginal Costs for Residential Single Family and Residential Multi-Family in its Distribution Marginal Cost Study because PGE is proposing a separate Basic Charge amount for Multi-Family. This amount is proposed in Exhibit 1201. Splitting out the marginal costs for Single-Family and Multi-Family allows PGE to show the difference in marginal costs to serve these two customer types and allocate the fixed costs appropriately.

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 was able to identify the number of residential customers that live in single-family housing and multi-family housing. PGE defines multi-family housing as housing with multiple attached units, including apartments, condos or townhomes, typically equipped with multiple meters. PGE calculated the marginal costs for multi-family and single-family for PGE's distribution system's Feeder Mainline, Feeder

Tapline, Secondary Tapline and Transformer & Service Costs. The marginal costs do not differ between multi-family and single-family for Transmission, Subtransmission, Substation and Meter Costs.

V. Customer Service Marginal Cost Study

Q. What is the purpose of the customer service marginal cost study?

A. The purpose 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 1101 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 2021 test period and 2020 actual costs to develop the 2022 test year Customer Service Marginal Cost Study. These costs are found in FERC Account Nos. 902, 903, 905, 908, and 909. The 2022 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 335?

A. Yes, the methodology is the same. As in UE 335, the costs are allocated by PGE accounts directly on the basis of 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 2022 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 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.
- Automated 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 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 will be 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. Similar to UE 335, we propose to base the test period lighting maintenance amount on the incurred maintenance amounts during PGE's most recent complete 5-year relamping cycle (2005-2009), before conversion to Light-Emitting Diode (LED) area and streetlights commenced. More specifically, we express the historical maintenance amounts on a per-light basis, and then escalate this per-light maintenance figure for inflation. A further reduction is made for LED street and area lights since (1) their maintenance is significantly less than other lights, and (2) the years used in the most recent 5-year re-lamping cycle do not include LEDs. Following this, we allocate maintenance to each type of luminaire based on the marginal cost of the maintenance study.

Q. Do you provide a summary exhibit of the proposed pole and luminaire prices?

A. Yes. This summary is provided in PGE Exhibit 1100.

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, OR, where I developed, prepared, and reviewed financial analyses used in securities litigation.

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

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	$55.93	$4.17	$10.68	$29.14	$36.19	$4.29	$74.68	$22.05	$44.42
Three-phase	$55.93	$4.17	$10.68	$29.14	$36.19	$4.29	$164.36	$51.68	$44.42
Schedule 7 Residential									
Single-phase Single-Family	55.93	4.17	10.68	31.02	43.99	5.21	76.13	22.05	
Single-phase Multi-Family	$55.93	$4.17	$10.68	$18.39	$20.18	$2.44	$54.87	22.05	
Schedule 15 Residential	55.93	4.17	10.68	30.41	38.12	2.44	2.42	N/A	$24.04
Schedule 15 Commercial	$55.93	$4.17	$10.68	$30.41	$38.12	$2.44	$2.42	N/A	$21.44
Schedule 32 General Service									
Single-phase	$55.93	$4.17	$10.68	$35.13	$58.44	$3.46	$157.85	$47.76	$46.23
Three-phase	$55.93	$4.17	$10.68	$35.13	$15.47	$0.92	$265.66	$66.13	$46.23
Schedule 38 TOU									
Single-phase	$55.93	$4.17	$10.68	$36.04	$60.92	$2.16	$165.25	$54.31	$125.69
Three-phase	$55.93	$4.17	$10.68	$36.04	$17.81	$0.63	$488.06	$108.52	$125.69
Schedule 47 Irrigation									
Single-phase	$55.93	$4.17	$10.68	$35.13	$58.44		$9.05	$54.86	$42.74
Three-phase	$55.93	$4.17	$10.68	$35.13	$15.47		$18.00	$75.87	$42.74
Schedule 49 Irrigation									
Single-phase	$55.93	$4.17	$10.68	$36.04	$60.92		$121.75	$54.86	$117.63
Three-phase	$55.93	$4.17	$10.68	$36.04	$17.81		$121.75	$65.99	$117.63
Schedule 83 Secondary General Service									
Single-phase	55.93	4.17	10.68	36.04	60.92	2.16	364.47	54.86	$236.02
Three-phase	$55.93	$4.17	$10.68	$36.04	$17.81	$0.63	$974.14	$114.60	$236.02
Schedule 85 Secondary General Service	$55.93	$4.17	$10.68	$27	6.72		$2,242.07	$123.23	$1,161.62
Schedule 85 Primary General Service	$55.93	$4.17	$10.68	$27	6.72		$0.00	$1,985.33	$1,161.62
Schedule 89 Secondary	$55.93	$4.17	10.68	$70,405 ($/Customer)	N/A		17117.73	$123.23	$7,007.37
Schedule 89 Primary	$55.93	$4.17	$10.68	$70,405 ($/Customer)	N/A		$0.00	$2,097.42	$7,007.37
Schedule 89 Subtransmission	$55.93	$4.17	N/A	$73,568.00 ($/Customer)	N/A		N/A	19844.95	$7,007.37
Schedule 90 Primary	$55.93	$4.17	$10.68	$331,061.00	NA		$0.00	2097.42	$42,796.56
Schedules 91 & 95 Streetlighting	55.93	$4.17	$10.68	$30.41	$38.12	$4.51	$2.42	N/A	$283.25
Schedules 92 Traffic Signals	55.93	4.17	10.68	30.41	15.03	0.09	7.72	N/A	223.91

Portland General Electric Company's Near Term Local Transmission Plan For the 2020-2021 Planning Cycle

December 23, 2020

Contents

1. Introduction

This 2020 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, Northwest Power Pool (NWPP) 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 2020-2021 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

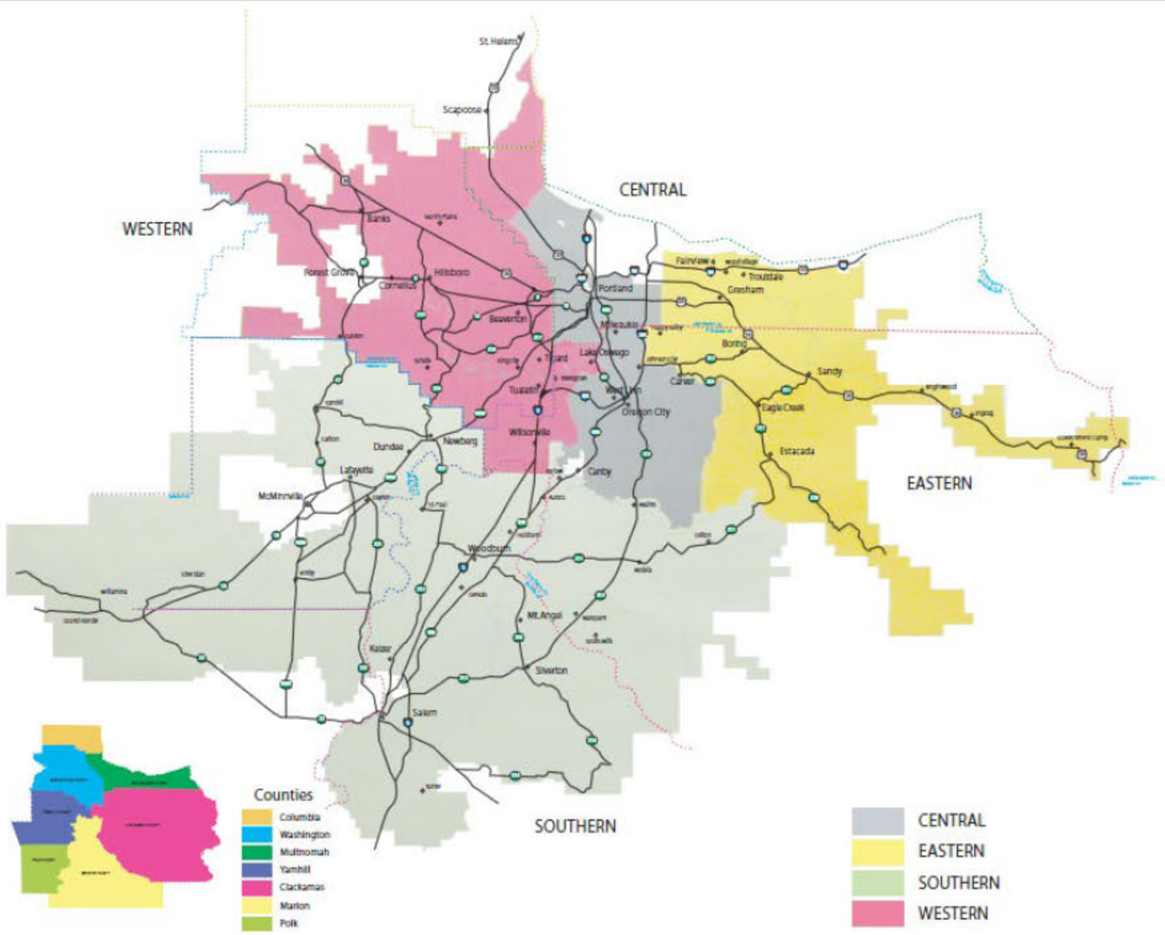
PGE updates its Transmission Customers about activities and/or progress made under the Attachment K planning process, during regularly scheduled customer meetings. Meeting announcements, agendas, and notes are posted in the *Customer Meetings* folder on PGE's OASIS. Meeting dates are also posted on PGE's 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 Rivergate-Trojan 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 1,625 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	514	565
57 kV	441	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.

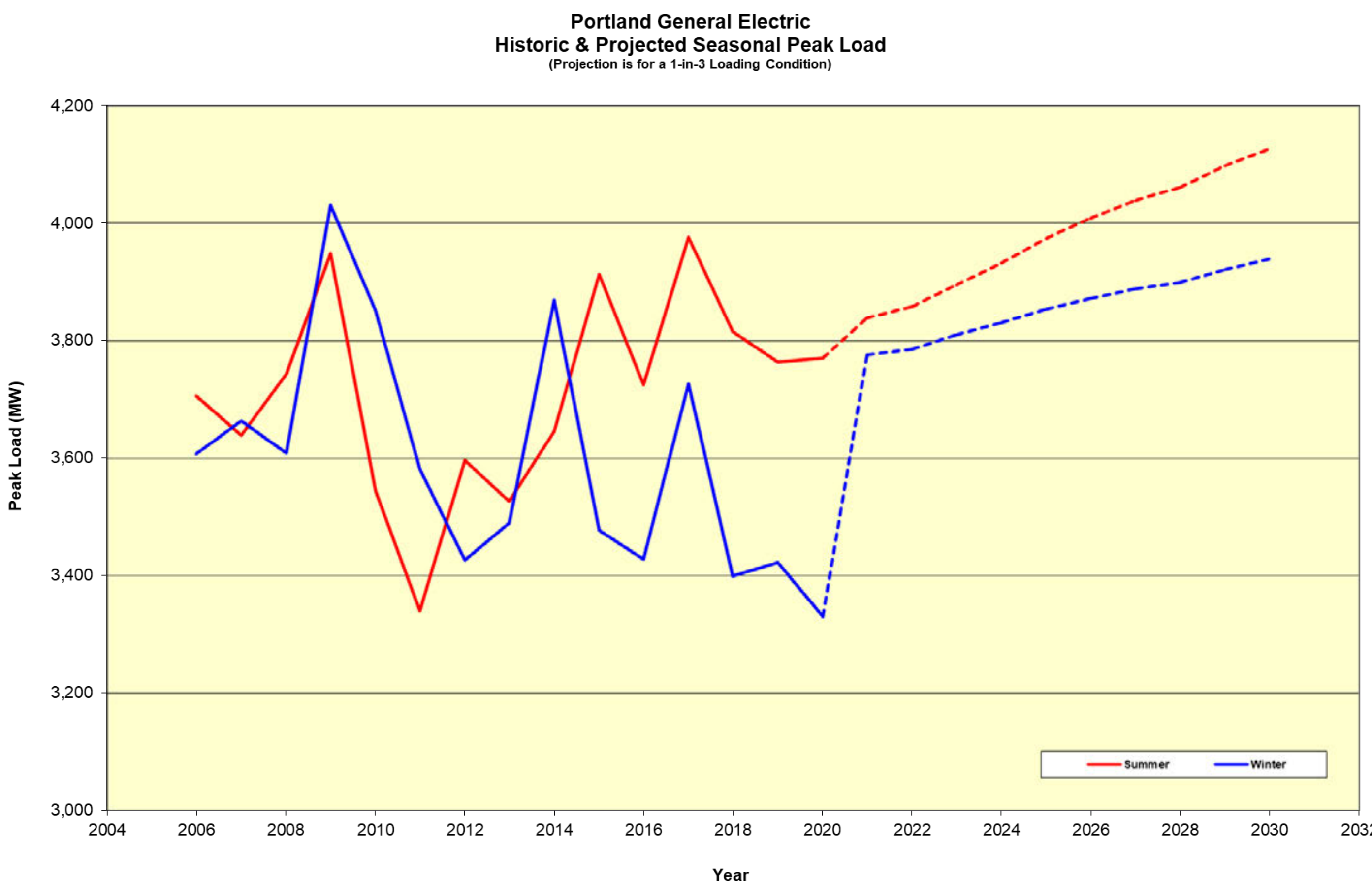
The 1-in-3 peak system load is calculated based on weather conditions that PGE can anticipate experiencing once every three years. The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads 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	81.9°F
1-in-3	83.4°F
1-in-5	84.6°F
1-in-10	86.1°F
1-in-20	87.3°F

Winter	
1-in-2	28.6°F
1-in-3	26.8°F
1-in-5	25.1°F
1-in-10	23.2°F
1-in-20	21.7°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 load occurred on December 21, 1998, with the Net System Load[1] reaching 4073 MW. PGE's all time summer peak occurred on August 3, 2017 with the Net System Load reaching 3974 MW.

[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.

3.3. 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.

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 2020-2021 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 2020-2021 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-3.2 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-008-3 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 and on the 57 kV distribution system.

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. 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 2020 Assessment

		Study Year	Origin WECC Base Case	PGE Case Name	PGE System Load (MW)
SUMMER	Year One/Two Case	2022	2020 HS3	22 HS PLANNING	4113
	Year Five Case	2025	2025 HS2	25 HS PLANNING	4484
	Year One/Two Sensitivity	2022	2020 HS3	22 HS SENSITIVITY	4275
	Year Five Sensitivity	2025	2025 HS2	25 HS SENSITIVITY	4634
	Long Term Case	2030	2030 HS1	30 HS PLANNING	4711
WINTER	Year One/Two Case	2022-23	2020-21 HW2	22-23 HW PLANNING	4019
	Year Five Case	2025-26	2024-25 HW2	25-26 HW PLANNING	4394
	Year One/Two Sensitivity	2022-23	2020-21 HW2	22-23 HW SENSITIVITY	4230
	Year Five Sensitivity	2025-26	2024-25 HW2	25-26 HW SENSITIVITY	4535
	Long Term Case	2030-31	2029-30 HW1	30-31 HW PLANNING	4595
SPRING	Year One/Two Off Peak Case	2022	2020 LSP1	22 LSP PLANNING	2249
	Year Five Off Peak Case	2022	2020 LSP1	25 LSP PLANNING	2558
	Year One/Two Off Peak Sensitivity	2022	2020 LSP1	22 LSP SENSITIVITY	2249
	Year Five Off Peak Sensitivity	2022	2020 LSP1	25 LSP SENSITIVITY	2558

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 Longer 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 distribution substations where manual post-contingency "load-shedding" may be required to ensure that the Transmission System remains within the defined operating limits.

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.

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.

[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
[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.

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.

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

Contingency loading concerns identified on PGE's system for the Near Term Planning Horizon due to the loss of either the Allston BPA-Keeler BPA 500 kV line or the Keeler BPA-Pearl BPA 500 kV line are mitigated by implementing BPA's DSO 309, addressing the South of Allston Path RAS.

Contingency loading concerns on the Redmond BPA-Round Butte 230 kV line due to the loss of both Ponderosa BPA 500/230 kV transformers are mitigated by implementing the Ponderosa RAS.

Contingency loading concerns in the North Portland area are mitigated by Phase 2 of the Harborton Reliability Project and PACW's Project to construct a new Albina PACW-Knott PACW-St Johns BPA 115 kV line.

Contingency loading concerns in the Beaverton area are mitigated by the second Horizon-Keeler BPA 230 kV line, the Harborton-Wacker 115 kV line (part of the Harborton Reliability Project), and the Canyon-Urban 115 kV Reconductor Project.

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. The transient voltage dip did not exceed 25% at any load bus or 30% at any non-load bus for any of the contingency events studied on PGE's system.

5.4. Near Term Short Circuit Analysis

The Near Term short circuit analysis identified three overdutied breakers; one at St Marys, one at Sherwood and one at Sunset. The St Marys breaker will be replaced as a part of the St Marys Battery Project. Projects will be evaluated to replace the Sherwood and Sunset overdutied breakers.

5.5. Projects Currently Included in the Near Term Plan

There are 15 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 VWR3 Project
- Helvetia Substation Project
- Kelley Point Reconfiguration Project
- St Marys Battery Project
- Northern 115 kV Conversion
- Butler Substation Project
- Murrayhill-St Marys 230 kV Reconductor Project
- Century Substation Project
- Canyon-Urban 115 kV Reconductor Project
- Sherwood Breaker Project
- Sunset Breaker Project
- Tonquin Substation Project
- Horizon-Keeler BPA #2 230 kV Project
- Arrowhead Substation Project

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 2025.

Horizon VWR3 Project

- **Project Purpose**
  - Provide an additional 115 kV source to the Hillsboro area.
- **Project Scope**
  - Install a third bulk power transformer at Horizon substation.
  - Create a Rock Creek-Shute-Sunset 115 kV circuit by tying the Rock Creek-Sunset 115 kV line and Shute-Sunset #2 115 kV line outside of Sunset substation (temporary configuration).
  - Build a new Horizon-Sunset #3 115 kV line.
- **Project Status**
  - Under Construction.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2021.

Helvetia Substation Project

- **Project Purpose**
  - Address new customer load with full N-1 distribution transformer redundancy.
- **Project Scope**
  - Construct a new 115 kV breaker and one half substation with two 115 kV line and two distribution transformer positions.
  - Loop the existing Shute-West Union 115 kV circuit into the substation, creating a Helvetia-Shute 115 kV line and a Helvetia-West Union 115 kV line.
- **Project Status**
  - Under Construction.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2021.

Kelley Point Reconfiguration Project

- **Project Purpose**
  - Mitigate the loss of the Kelley Point substation for the loss of the Rivergate 115 kV bus.
- **Project Scope**
  - Reconfigure the Harborton-Rivergate 115 kV, the Rivergate-Kelley Point 115 kV, and the Rivergate-Hayden Island 115 kV lines to provide sources to Kelley Point substation from two different substations.
- **Project Status**
  - Project approved for preliminary engineering.
- **Project Requirement Date**
  - The project is currently projected for completion by Q3 2021.

St Marys Battery Project

- **Project Purpose**
    - Address a single point of failure at St Marys substation.
    - Replace antiquated 230 kV relays at St Marys substation.
    - Mitigate the St Marys V286 overdutied breaker.
- **Project Scope**
    - Install a second control enclosure with all new 230 kV relaying.
    - Install a second station battery to eliminate a single point of failure.
    - Replace the St Marys V286 230 kV breaker with a 50 kA breaker.
- **Project Status**
    - Design complete Q4 2019, construction scheduled to start Q1 2021.
- **Project Requirement Date**
    - The project is currently projected for completion by Q4 2021.

Northern 115kV Conversion

- **Project Purpose**
  - Address loading concerns on the Knott PACW-St Johns SS PACW 115 kV line.
  - Address aging infrastructure at Northern substation
- **Project Scope**
  - Rebuild the Northern substation to a 115 kV breaker station
  - Loop the Curtis-Rivergate #2 115 kV line into Northern substation creating the Curtis-Northern 115 kV line and the Northern-Rivergate 115 kV line.
- **Project Status**
  - Design in progress.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2022.

Butler Substation Project

- **Project Purpose**
  - Address new customer load with full N-1 distribution transformer redundancy.
- **Project Scope**
  - Construct a new 115 kV breaker and one half substation with four 115 kV line and two distribution transformer positions (future third position).
  - Loop the existing Orenco-Sunset 115 kV circuit and the St Marys-Sunset 115 kV circuit into Butler substation, creating the Butler-Orenco 115 kV, Butler-St Marys 115 kV, Butler-Sunset #1 115 kV, and Butler-Sunset #2 115 kV circuits.
  - Install two 115 kV, 24 MVAR cap banks for voltage support.
- **Project Status**
  - Under Construction.
- **Project Requirement Date**
  - Phase 1 of this project will include the substation work and looping in all of the lines into the substation and is scheduled for completion by Q4 2020.
  - Phase 2 of this project will reconductor the existing St Marys-Sunset 115 kV line to 795 ACSS and is scheduled for completion by Q2 2022.

Murrayhill-St Marys 230 kV Reconductor

- **Project Purpose**
  - Address loading concerns on the Murrayhill-St Marys 230 kV line.
- **Project Scope**
  - Reconductor the Murrayhill-St Marys 230 kV line to 1272 ACSS.
- **Project Status**
  - Design in progress.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2022.

Century Substation Project

- **Project Purpose**
  - Address new customer load with full N-1 distribution transformer redundancy.
- **Project Scope**
  - Construct a new 115 kV breaker and one half substation with three 115 kV line and four distribution transformer positions (initial buildout will be two transformers).
  - Loop the Helvetia-West Union 115 kV circuit into the substation, creating a Century-Helvetia 115 kV line and a Century-West Union 115 kV line.
  - Relocate the spare 115/57 kV transformer to Century and purchase a new spare.
  - Rebuild the existing Banks-Orenco 57 kV line between Century and Orenco to 115 kV, creating the Century-Orenco 115 kV circuit.
  - Terminate the Banks-Orenco 57 kV line at Century, creating the Banks-Century 57 kV circuit.
- **Project Status**
  - Design in progress.
- **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 2022.
  - Phase 2 of this project will re-terminate the Orenco end of the Banks-Orenco 57 kV line at Century, install a 115/57 kV transformer at Century, and rebuild the idled 57 kV line to create the Century-Orenco 115 kV circuit. This phase is scheduled for completion by Q2 2023.

Canyon-Urban 115 kV Reconductor

- **Project Purpose**
  - Address loading concerns on the Canyon-Urban 115 kV line.
- **Project Scope**
  - Reconductor the Canyon-Urban 115 kV line to 795 ACSS.
- **Project Status**
  - Design in progress.
- **Project Requirement Date**
  - The project is currently projected for completion by Q3 2022.

Sherwood Breaker Project

- **Project Purpose**
  - Mitigate the Sherwood V274 overdutied breaker.
- **Project Scope**
  - Replace the Sherwood V274 230 kV breaker with a 50 kA rated breaker.
- **Project Status**
  - This project will be developed in 2021 for implementation in 2022.
- **Project Requirement Date**
  - The project is currently projected for completion by Q4 2022.

Sunset Breaker Project

- **Project Purpose**
  - Mitigate the Sunset W196 overdutied breaker.
- **Project Scope**
  - Replace the Sunset W196 115 kV breaker with a 63 kA rated breaker.
- **Project Status**
  - This project will be developed in 2021 for implementation in 2022.
- **Project Requirement Date**
  - The project is currently projected for completion by Q4 2022.

Tonquin Substation Project

- **Project Purpose**
    - Address new customer load.
    - 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**
    - This project is in initial development stages.
- **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.

Horizon-Keeler BPA #2 230 kV Project

- **Project Purpose**
  - Address loading concerns on the 230 kV and 115 kV system in the Hillsboro area.
- **Project Scope**
  - Construct a second 230 kV line between PGE's Horizon Substation and BPA's Keeler Substation.
- **Project Status**
  - Project identified in current TPL process.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2025.

Arrowhead Substation Project

- **Project Purpose**
  - Address new customer load.
- **Project Scope**
  - Construct a new 115 kV breaker 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 Arrowhead-Sherwood 115 kV line and an Arrowhead-Wilsonville 115 kV line.
- **Project Status**
  - This project is in initial development stages.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2025.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Robert Macfarlane
Teresa Tang

July 9, 2021

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Robert Macfarlane. I am Manager of Pricing and Tariffs for Portland General Electric Company (PGE). My qualifications are included at the end of this testimony.

My name is Teresa Tang. I am a Regulatory Consultant in Pricing and Tariffs for 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-18 Tariff changes recover PGE's 2022 revenue requirement in a way that achieves fair, just, and reasonable prices for all of 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 also:

1. Support changes to the Basic Charge for multifamily and single-family Schedule 7 residential customers;
2. Support changes to eliminate the blocking associated with Schedule 7 residential customers;
3. Address load following credit, eligibility criteria, and pricing differentiation for Schedule 90;
4. Introduce a nonresidential new-large load cost of service (COS) schedule;
5. Support limited changes to, and extension of, PGE's decoupling mechanism Schedule 123;

6. Support changes to one supplemental schedule to implement nonbypassability of costs associated with the state's solar payment option program, allocating costs to all PGE customers;
7. Introduce two new supplemental schedules to recover costs related to energy storage and transportation electrification;
8. Summarize the update to prices contained in Schedule 108, Schedule 146, Schedule 300, Charges as Defined by the Rules and Regulations and Miscellaneous Charges; and
9. Support changes to line losses.

Q. Does this case include estimates costs from bills passed in the recent legislative session?

A. No. A number of bills passed that may change prices for customers. We are evaluating those bills over the coming months but have not determined how they impact customer prices. Some of those bills may need Commission process to develop frameworks before we understand the eventual impacts.

Q. Please summarize the projected 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 impact. PGE Exhibit 1202 contains more detailed information on the rate impacts for the individual schedules. Table 1 of PGE Exhibit 1202 contains the base rate impacts of the proposed prices effective May 1, 2022. The detailed bill impacts starting on page 2 of PGE Exhibit 1202 relate to prices effective May 1, 2022, 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.[1]

Schedule	May. 1, 2022
Schedule 7 Residential	6.4%
Schedule 32 Small Nonresidential	7.8%
Schedule 83 31-200 kW	4.4%
Schedule 85 201-4,000 kW	0.0%
Schedule 89 Over 4,000 kW	0.0%
Schedule 90 30 MWa	-3.2%
COS & DA Overall	3.9%

[1] This represents the increase on a cycle basis. Without the Customer Impact Offset (CIO), impacts for Schedules 7, 32, 85 and 89 are 6.9%, 9.7%, -1.8% and -1.9% respectively.

II. UE 335 Stipulations

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

A. The purpose of this portion of our testimony is to discuss the treatment of generation demand charges for Schedules 83 and 85 as directed in the third stipulation from Docket No. UE 335 and to address the location change fee charged to Electricity Service Suppliers (ESS) per Schedule 600, either justifying the charge or proposing revisions to it as directed in the fifth stipulation

Q. What did the third UE 335 stipulation direct PGE to address regarding generation demand charges for Schedules 83 and 85?

A. The stipulation directs PGE to either propose on-peak generation demand charges for Schedules 83 and 85 or explain why it does not support on-peak generation demand charges for Schedules 83 and 85.

Q. Do you propose to implement on-peak generation demand charges for Schedules 83 and 85?

A. No, not in this case. Proposing a new on-peak generation demand charge now would create complexity and future alignment challenges once the Commission makes findings related to resource adequacy (RA) in Docket UM 2143. where the Commission is examining concerns about resource adequacy and system reliability and addressing the inequity that currently exists between utilities and ESSs with regard to the responsibility and cost to supply RA resources. In UE 358, PGE demonstrated, and the Commission agreed, that resource adequacy is a significant issue.[2] PGE is interested in implementing a thoughtful on-peak generation demand charge in conjunction with volumetric time varying charges after the

[2] Commission Order No. 20-002.

resource adequacy and cost allocation issues are resolved in UM 2143. The Northwest Power Pool (NWPP) is continuing its efforts to develop a regional RA program that aims to complement existing utility practices, such as resource planning and procurement, through an Integrated Resource Plan, and capture benefits through regional diversity and visibility. While this work is progressing at a rapid pace, it is still in program development stages and it is likely to be several years before the RA program is fully operational. PGE continues to actively participate in the NWPP RA effort and supports it moving forward; however, there are still multiple elements of RA that will need to be addressed at the state level through UM 2143 to ensure supply reliability. ESS energy pricing currently lacks a price component to reflect the provision of and cost of resource adequacy when providing energy to customers. An implementation of a new on-peak generation demand charge would widen the pricing differences between COS and ESS customers, further exacerbating the price inequity. Therefore, now is not the time to modify PGE's pricing for large nonresidential customers without first addressing resource adequacy for all customers.

Q. Do you have any other reasons why now is not the right time to propose on-peak generation demand charges for large nonresidential customers?

A. Yes. PGE is evaluating software options to assist diagnostic and analytical frameworks in pricing that would connect to our billing software and allow PGE to produce more comprehensive pricing analyses. We could then model potential impacts of such a change on all customers in those classes. We want to make sure we have smooth transitions between rate schedules and that we avoid undue price shock to individual customers. Such pricing software would enable us to do so more efficiently.

Q. What did the fifth stipulation direct PGE to address regarding Schedule 600 fees charged to ESSs for Customer Change of Location charges?

A. The stipulation directs PGE to address the $7,000 location change fee charged to ESSs per Schedule 600, to either justify the charge or propose revisions to it.

Q. How does PGE address the location change fee charged to ESSs?

A. PGE is proposing to reduce the location change fee charged to ESSs from $7,000 to $5,000. The $7,000 Customer Change of Location charge in Schedule 600 was derived based on system process steps and costs stated in 2013 dollars. Since 2013 PGE has implemented a new Customer Information System and Meter Data Management System. The system process steps to accept or reject a Direct Access enrollment outside of an election window that were manually performed previously have changed and now can be performed at a lower cost. All process step costs which includes coordination efforts amongst Service and Design, Key Customer Management, Direct Access Operations, Legal and Billing groups have been updated using 2021 costs.

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 1101.

Q. How do you calculate and allocate the 2022 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 described in PGE Exhibit 1100 by the projected 2022 COS peak-hour load. This peak-hour load is projected to occur in December. We then allocate the marginal generation capacity costs on the basis of each rate schedule's relative contribution to the monthly peak hours contained in the months of January, July, August, and December (4-coincident peak or 4CP).

Q. Why do you choose these four months?

A. We choose these four months because they are the months with the highest peaks consistent with the periods identified as capacity deficient in PGE's 2019 Integrated Resource Plan. Additionally, we choose these four months because PGE's highest annual peak hours generally occur during one of these four months.

Q. What are the respective capacity and energy percentages used in allocating the generation revenue requirements?

A. Capacity comprises approximately 31.0% of the marginal cost of generation, and energy approximately 69.0%. These figures reflect the inclusion of load following costs as a capacity cost. The corresponding figures from UE 335 were approximately 34.4% and 65.7%.

Q. How do you allocate the transmission revenue requirement?

A. As stated above, we allocate the transmission revenue requirement on the basis of each rate schedule's 12 monthly coincident peaks (12CP) times the unit marginal transmission costs presented in PGE Exhibit 1101 as was done in UE 335.

Q. Parties to recent proceedings have argued that transmission lines functioning as generation leads should be allocated on the basis of both capacity and energy. Do you agree?

A. Yes.

Q. Please describe how PGE functionalizes transmission lines that serve as generation leads.

A. PGE 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 on the basis of both capacity and energy. Furthermore, PGE's wheeling expense from purchasing Bonneville Power Administration (BPA) transmission is functionalized to generation and allocated on the basis of 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 its coal plant Colstrip, and its 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. Both the Colstrip transmission line and the Grassland switchyard, constructed to connect Carty to BPA's Slatt substation via the Boardman-Slatt generation lead, are also functionalized to the generation revenue requirement. As a result of this functionalization, the majority of the transmission used to bring Carty, and Colstrip 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 complete the seven functional categories specified in ORS 757.642.

Q. Do you allocate other cost categories to the individual rate schedules?

A. Yes. We allocate franchise fees to the schedules on the basis of the test period revenue requirement allocations and 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 general rate cases. Finally, we allocate uncollectible expense based on historical incidence for the period May 2018 to December 2020. All allocations are presented in PGE Exhibit 1204.

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 335 and other recent dockets. Therefore, we do 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 outdoor lighting schedules 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 of the cost categories are facilities with the same unit marginal cost. However, because Schedule 90 has only one customer with four accounts engaging in similar activity, there is virtually no diversity of the demand billing determinants relative to Schedule 89 that has multiple customers engaged in different manufacturing activities. The differences in diversity of demand billing determinants is 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 their unique costs attributions that yield reasonable prices.

IV. Resource Adequacy Pricing

Q. In PGE's New Load Direct Access tariff filing, UE 358, PGE proposed a resource adequacy charge on new load direct access participants, which the Commission rejected. Is PGE proposing a resource adequacy charge in this rate case?

A. No. In the Commission order rejecting PGE's proposed resource adequacy charge for new load direct access customers, the Commission acknowledged that "PGE is accountable for system reliability within its BA, and resource adequacy is an important component of reliability." The Commission went on to state that it must provide PGE the tools and framework to achieve RA and that means that all customers equitably benefit and contribute. The Commission notes that UM 2024 is the appropriate docket to explore the questions raised. In UM 2024 (now UM 2143 as the Commission subsequently separated RA from other direct access issues), PGE and others are encouraging the Commission to adopt an RA framework for all load serving entities (LSE) to ensure that all load serving entities fairly support resource adequacy. The docket is ongoing, and we are hopeful that we reach resolution on a state RA framework for all LSE's expeditiously. When the investigation is complete, PGE anticipates pricing resource adequacy based on the requirements established by the Commission. PGE recognizes that the NWPP RA effort is currently underway, but as indicated above, there is still elements of RA that will not be addressed by the NWPP work and should be taken up in UM 2143 to ensure a robust RA framework in Oregon.

V. 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 a two-block energy rate. We propose to split the Basic Charge into separate charges for multi-family and single-family dwellings. The Company proposes increasing the basic charge from its current level of $11.00 per month to $12.50 for single-family dwellings and decreasing it to $8.00 for multi-family dwellings. This charge better reflects the fixed costs of serving residential customers and more accurately recovers costs from customers who live in multi-family dwellings and have a lower cost of service. The Company is also proposing to reduce the block energy rate differential for all the 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), is applicable 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 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 mandatory Time-of-Use (TOU).

Schedule 85, Large Nonresidential Standard Service (201 kW to 4,000 kW), is applicable 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 proposed Energy Charges continue to be on- and off-peak differentiated.

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.

Currently, Schedule 90 is for customers whose Facility Capacity Exceeds 4,000 kW and whose aggregate energy consumption exceeds 100 MWa. We propose to adjust the eligibility down to an aggregate consumption of 30 MWa and include two sets of energy charge prices differentiated at 250 MWa. The purpose of this differentiation is to recognize the load stability value of the energy of mega-sized customers for improved cost allocation. It also provides a lower threshold for any new customers that are significantly larger than the existing Schedule 89 customers.

Q. Do you propose to continue the load following/integration credit for Schedule 90?

A. Yes, in concept. We propose to continue this concept, applicable to 250 MWa instead of the 150 MWa used previously, and to incorporate the credit amount of approximately $3.2 million into the base energy charges for Schedule 90 customers. In addition, it would only apply to the over 250 MWa portion of Schedule 90 energy charges. This $3.2 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 cost of service rate classes for non-residential customers 20 years ago initially to enable SB 1149 with recognition of only two nonresidential base rate schedules (Schedule 32 and Schedule 83). Over time, that evolution lead 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, even 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[3] 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 1203, 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.

[3] "Principles of Public Utility Rates," by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, 2nd Edition, 1988.

A. The prices are summarized below:

Table 2
Schedule 7 - Residential Service Proposed Prices

Category	Prices
Basic Charge – Multifamily	\$8.00 per customer per month
Basic Charge – Single Family	\$12.50 per customer per month
Transmission & Related Service Charge	6.01 mills per kWh
Distribution Charge	56.51 mills per kWh
Energy Charge First 1,000 kWh	66.36 mills per kWh
Energy Charge Over 1,000 kWh	69.96 mills per kWh

Q. Please explain how you develop these prices.

A. We propose to 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 \$25, we propose to decrease the Basic Charge from \$11.00 monthly to \$8.00 for multi-family dwellings and increase the Basic Charge from \$11.00 monthly to \$12.50 for single-family dwellings in order to better match prices to embedded costs, consistent with the principles discussed above, and recognize the lower costs to serve and differences in income and energy burden between customers in multi-family versus single-family dwellings.

We develop the **Transmission & Related Service Charge** directly from the allocated transmission and ancillary services revenue requirement.

We calculate the **Distribution Charge** of 56.51 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.

We maintain the Schedule 7 blocked **Energy Charges** structure of under/over 1,000 kWh but reduce by half the price differential to 3.60 mills per kWh.

Q. Why does the Company propose a separate basic charge for the multi-family customers?

A. Multi-family dwelling includes condos and apartment buildings with higher density, clustered within urban areas. Customers who live in the multi-family dwelling units tend to use less energy than the single-family customers. Lower energy usage in multi-family can be partially explained by their smaller living space, which need less heating and cooling energy compared to the single-family customers. The fixed cost of servicing the multi-family customers are expected to be lower than the single-family customers. Marginal distribution costs are largely driven by the number of customers on average who utilize a shared distribution system. On average for the entire residential class, 8.43 customers are served from a transformer. This value is significantly different for multi-family and single-family customers. On average, 8.01 single-family residential customers are served by a transformer compared to 29.4 multi-family customers per transformer. The cost associated with stepping down the voltage to serve is spread over more customers and reduces the marginal cost for the multi-family customers.

Q. What is the basis for calculating the cost to serve multi-family customers? How is it different from the single-family customers?

A. PGE used the marginal cost study to specify the cost of serving residential customers. After splitting the marginal cost for single-family and multi-family customers in the following cost categories,[4] PGE was able to identify the cost differentiation between these two groups of customers. PGE Exhibit 1205 shows the results of this analysis which calculates that the marginal distribution and customer costs for a multi-family residential customer is $13.53 per month, or about 27 percent lower than the same value for single-family residential customers of $18.57. Applying the 27 percent difference in marginal cost resulted in a value of $8.00

[4] Cost categories include feeder mainline, feeder tapline, secondary tapline, transformer, meter, billing, and collections.

for multi-family for its proposed multi-family basic charge. Assuming revenue neutral rates, PGE proposed a 14 percent increase from the current basic charge of $11.00 to $12.50 for single-family customers. If only reducing the multi-family basic charge without the corresponding upward adjustment of the single-family basic charge, PGE will under recover approximately $9.7 million of basic charge revenue.

Q. What structural change is proposed for Schedule 7?

A. We propose to reduce the energy charge blocking differential from 7.22 mills per kWh to 3.60 mills per kWh. This is a continuation of changes we made in UE 335. In that rate case we removed the blocking for Schedule 102 applicable to residential customers over two years. We recommend a similar gradualism in this case to remove the blocking in the energy charge. However, the full removal of the blocking would take place in PGE's next general rate case, rather than the next calendar year.

Q. Why do you propose to remove the Schedule 7 energy charge blocking?

A. The initial goals of energy charge blocking include encouraging energy efficiency and conservation, as well as maintaining energy affordability for low-income customers. However, PGE found that the current blocking rate does not align with the designed goals when 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 the transportation electrification less attractive. Finally, it adds complexity to PGE's TOU rate options (both legacy and new TOU rates) and makes the rates very hard to be understood by residential customers, yet the conservation signal is already muted in the TOU structure.

Low income does not simply translate into low usage. On the contrary, low-income customers tend to use more energy and are subject to the higher block pricing than non-low-income customers due to the consumption pattern and dwelling characteristics. Referring to Table 3, in 2020, PGE service territory had about 14% low-income customers and 86% non-low-income customers. On an annual basis, about 28.3% low-income customers use more than 1,000 kWh in a month and only 26.7% non-low-income customer energy usage is over 1,000 kWh. During the winter months (November to April), 36.9% of low-income customers consume over 1,000 kWh compared to 31.7% of non-low-income customers. Customers energy usage increased in the winter and this seasonal effect disproportionally impacted low-income customers, as low-income customer energy usage increased 3.6% more than the non-low-income customers.

Table 3
Customer Usage Profile in 2020

2020 Actuals	% of Total Customers Counts	% of Total Customers Usage > 1000 kWh	% of Total Customers Usage > 1000 kWh in Winter (November to April)
Low Income	14%	28.3%	36.9%
Non-Low Income	86%	26.7%	31.7%

PGE is committed to supporting the growth of EVs and developing incentives to encourage charging during non-peak hours. The energy charge blocking is a disincentive to home charging, ignoring the time-sensitive nature of 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.

On May 1, 2021 PGE launched a new residential Time of Use (TOU) rate which introduced a larger differential between on- and off-peak prices, muting the conservation signal from the energy charge blocking. Furthermore, one of our primary goals in the design of the new TOU rate is to keep the structure as simple as possible, recognizing that residential customers want simple and easy to use offerings and pricing. Removing the blocking aspect from the TOU rate would advance this goal significantly but would also require removing the blocking from the standard residential rate. The TOU rates (current and new) are 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 the rates, the TOU rate needs to include the same blocking that is in the standard rate; otherwise, it would be harder for many customers to save on the new TOU rate even if they shift use to off peak, and they will be less likely to opt in.

Q. Do you incorporate a projection of the revenue impacts of the Schedule 7 voluntary portfolio TOU option in the calculation of the energy, transmission, and distribution prices?

A. Yes, but only for customers on the legacy TOU. 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 $342,000. We incorporate this impact in the standard Schedule 7 energy, transmission, and distribution charges.

Q. Please list the individual monthly prices for Schedule 32, Small Nonresidential Service.

A. The prices are summarized below:

Table 4
Schedule 32 - Small Nonresidential Service

Category	Prices
Basic Charge Single Phase	$20.00 per customer per month
Basic Charge Three Phase	$29.00 per customer per month
Transmission & Related Services Charge	4.79 mills per kWh
Distribution Charge First 5,000 kWh	54.08 mills per kWh
Distribution Charge Over 5,000 kWh	13.29 mills per kWh
Energy Charge	57.35 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.

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 13 mills per kWh (prior to adding the System Usage Charge) in order 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 $42,000. 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 one exception, a 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:

Table 5
Schedule 83 - General Service 31-200 kW

Category	Monthly Price
Basic Charge Single Phase	$35.00 per customer per month
Basic charge Three Phase	$45.00 per customer per month
Trans & Related Services	$1.86 per on-peak kW
Facility Capacity Charge (First 30 kW)	$5.12 per kW Facility capacity
Facility Capacity Charge (Over 30kW)	$5.02 per kW Facility Capacity
Distribution Demand Charge	$1.60 per on-peak kW
COS Energy Charge On-peak	62.00 mills per kWh
COS Energy Charge Off-peak	47.00 mills per kWh
System Usage Charge	8.64 mills per kWh

Q. Please describe how you develop the Schedule 83 prices.

A. We propose to maintain the current Schedule 83 single-phase **Basic Charge** of $35.00 and the three-phase charge of $45.00. 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 $1.86 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 a 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 once again 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 **Demand Charge,** which recovers distribution substations and 115 kV costs where applicable, at $1.60 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, maintaining the current on-and off-peak differential at 15 mills per kWh.

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 from a PGE market option receive the Schedule 128, Short-Term Transition Adjustment.

Q. What schedule is applicable to Schedule 83 customers who wish to elect the Direct Access energy option?

A. Customers choosing the Direct Access energy option will take service under the provisions of Schedule 583. Schedule 583 pricing mirrors Schedule 83 except that it contains neither a PGE-supplied energy price, nor a Transmission & Related Services Charge. In addition, consistent with the franchise fee discussion above, the System Usage prices for Schedule 583 are lower than those for Schedule 83. This is also true for Schedules 485/585, 489/589, and 490/590 relative to their COS equivalent schedules.

Q. Please provide the proposed monthly prices for Schedule 85 and describe the customers to whom these prices apply.

A. Schedule 85 applies to all Large Nonresidential customers whose Facility Capacity demands are between 201 kW and 4,000 kW. Those customers whose facility capacity exceeds 4,000 kW take service under Schedule 89, which we discuss below. We base the individual charges on the results of the marginal cost study and subsequent rate-spread, paying particular attention to appropriately pricing the cost differentials between secondary and primary delivery voltages. The prices differentiated by delivery voltage are in Table 6 below:

Table 6
Schedule 85 General Service 201-4,000 kW

Category	Secondary Prices	Primary Prices
Basic Charge	$810.00 per customer per month	$760.00 per customer per month
Trans & Related Services	$1.86 per on-peak kW	$1.84 per on-peak kW
Facility Capacity Charge (First 200 kW)	$3.48 per kW Facility Capacity	$3.45 per kW Facility Capacity
Facility Capacity Charge (Over 200 kW)	$2.28 per kW Facility Capacity	$2.25 per kW Facility Capacity
Distribution Demand Charge	$1.60 per on-peak kW	$1.58 per on-peak kW
COS Energy Charge On-peak	60.01 mills per kWh	59.41 mills per kWh
COS Energy Charge Off-peak	45.01 mills per kWh	44.41 mills per kWh
System Usage Charge	3.08 mills per kWh	3.06 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 $810 and $760, respectively. These Basic Charges, subject to rounding, recover the full amount of the allocated customer-related costs with the exception of 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 $1.86 per kW of on-peak demand for secondary service, and to $1.84 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 Facilities Capacity Charge also recovers any over- or under-recovery of the other charges.

The **Demand Charges** of $1.60 and $1.58 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. We maintain the current on- and off-peak differential of 15 mills/kWh. 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 7 below:

Table 7
Schedule 89 General Service Greater than 4,000 kW

Category	Secondary Prices	Primary Prices	Subtransmission Prices
Basic charge	$5,380 per month	$3,630 per month	$5,680 per month
Transmission & Related Charge	$ 1.86 per on peak kW	$1.84 per on peak kW	$1.81 per on peak kW
Facility Capacity Charge First 4,000 kW	$1.35 per kW Facility Capacity	$1.34 per kW Facility Capacity	$1.34 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.04 per kW Facility Capacity	$1.03 per kW Facility Capacity	$1.03 per kW Facility Capacity
Distribution Demand Charges	$1.60 per on-peak kW	$1.58 per on-peak kW	$0.50 per on-peak kW
COS Energy Charge On-peak	59.14 mills per kWh	58.56 mills per kWh	57.97 mills per kWh
COS Energy Charge Off-Peak	44.14 mills per kWh	43.56 mills per kWh	42.97 mills per kWh
System Usage Charge	2.52 mills per kWh	2.51 mills per kWh	2.49 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 four cents/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/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/kWh, the same differential as for Schedules 83 and 85. A Daily Price option is also available similar to that described for Schedule 83. Customers who wish to pursue the Direct Access Energy Option will take service under Schedule 589. As with Schedules 83/583 and 85/485/585, Schedules 89 and 489/589 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 four of the accounts on Schedule 90 are served at primary delivery voltage; the prices are listed in Table 8 below:

Table 8
Schedule 90 General Service Greater than 4,000 kW aggregating to 30/250 MWa

Category	Primary Voltage Prices
Basic Charge	$20,900 per month
Transmission & Related Charge	$1.84 per on-peak kW
Facility Capacity Charge First 4,000 kW	$1.70 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.39 per kW Facility Capacity
Distribution Demand Charge	$1.58 per on-peak kW
COS Energy Charge On-peak (30-250MWa)	56.52 mills per kWh
COS Energy Charge Off-peak (30-250 MWa)	41.52 mills per kWh
COS Energy Charge On-peak (>250 MWa)	55.39 mills per kWh
COS Energy Charge Off-peak (>250 MWa)	40.39 mills per kWh
System Usage Charge (30-250 MWa)	1.00 mills per kWh
System Usage Charge (>250 MWa)	0.98 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** of $1.58 per kW of on-peak demand is also calculated in conjunction with Schedules 83, 85, and 89.

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 hours with a 15 mills/kWh differential. 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-Day Standard Service** is, as its name implies, an optional schedule that is applicable to customers whose facility capacity is between 31 and 200 kW. We propose to maintain the monthly Basic Charge of $30 for single- and three-phase service customers. 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/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 maintain the Basic Charge of $37 per month, applicable during the months of May through October. We maintain the blocked volumetric distribution charges for these schedules as well as the volumetric recovery of transmission and generation costs. The direct access equivalent schedule for Schedule 47 is Schedule 532.

Schedule 49, Irrigation and Drainage Pumping Large Nonresidential Standard Service, is similar to Schedule 47, but applies to customers larger than 30 kW. We propose to maintain the Basic Charge at $45. 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 1206.

Schedule 92, Traffic Signals Standard Service, is an energy-only rate for un-metered 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.

Q. Why and how do you limit the amount of increase to some rate schedules?

A. We limit the increases to Schedules 7 and 32 customers by removing the decreases associated with Schedules 85/485/585/89/498/589. Schedule 32 is limited to twice the overall increase. After the CIO, Schedules 85 and 89 receive neither a decrease nor an increase on an all-in price change basis (excluding Public Purpose Charge (PPC), Low Income Assistance, and local taxes). As specified earlier, we use the CIO to equalize the distribution prices for the outdoor lighting schedules because of the similar nature of the services provided.

Q. How do you implement the CIO?

A. For Schedules 7 and 32, we decrease the distribution charges while increasing the system usage charges for Schedules 85/485/585/89/498/589. For Schedule 15, we increase the distribution charge while reducing the distribution charges for Schedules 91 and 95.

VI. Streetlights

Q. Please describe the changes you propose in the pricing of Area Lights and Streetlights.

A. Due to the nature of Light Emitting Diode (LED) technology, streetlights are continuing to become more efficient and the wattages are decreasing for the same number of nominal lumens. In their current states, all LED options in Schedule 15 as well as Options A and B for Schedules 91 and 95 are classified by the type of light and various wattages. PGE is proposing to create buckets of wattages for each LED lighting option that will mirror Option C (customer owned streetlights). PGE also proposes to create buckets based on the cost of the light and maintenance for purposes of the non-energy charge per luminaire. This change will only impact LEDs as other lighting technology is not gaining efficiencies like LED lighting is.

Q. Why does PGE propose to create buckets for luminaire and energy charges?

A. PGE seeks to make this change to reduce the amount of administrative burden and to make the lighting tariff more customer-centric. Currently there are numerous options for lighting and each time there is a change in the wattage for LED lighting, a new light must be added, or the light must be put in the closest current option for billing purposes. Creating buckets will minimize the need to create more new lighting options and will simplify the number of billing options for customers.

Q. Is PGE proposing any other changes to lighting schedules?

A. PGE is not proposing any other structural changes to lighting schedules. The allocation methodologies are consistent with PGE's previous general rate case.

VII. Other Rate Schedule Changes

A. Large New Load COS

Q. Please describe PGE's Large New Load COS concept.

A. To provide the Commission and parties with greater transparency to our planning efforts we describe here, for informational purposes, a concept we have been developing that, with further refinement and finalization, would lead to a future tariff filing.

The concept is a new schedule for large new load cost of service to price energy, and potentially resource adequacy, based on new resource costs. The option would likely be available to new customers greater than 30 MWa, consistent with our proposed changes to the minimum threshold for Schedule 90. The remaining eligibility criteria would be similar to Schedule 689. The remaining non-generation charges would match those in Schedule 90.

Q. Why is PGE not proposing this new large load schedule in this GRC?

A. As we previously discussed, it is imperative that the Commission adopt a resource adequacy framework first. This would allow us to properly identify resource adequacy costs within our current generation portfolio and to establish prices for each function that would be applicable to all cost of service customers. Further, the RA framework would allow us to appropriately identify marginal resources that provide RA and could be used to price the RA component of a new large load cost of service option.

Q. What value would a new large load cost of service schedule potentially provide?

A. Just as in the NLDA setting, customers with significant new loads want to influence and help shape the resources that are used to serve their energy needs. Increasingly, these new large loads have aggressive renewable or clean energy targets that strongly influence their location preferences. This is important for two reasons: 1) Being able to attract new customers is beneficial to the overall system as it allows for efficiencies in cost and diversity of load and 2) As PGE and its current customers continue to decarbonize our system, new large loads are likely to view that progress as a benefit and likely desire to site within PGE's service territory. While that new load has benefits, it can also introduce costs as clean energy standards or legislative requirements may need to be met, requiring PGE to secure resources specifically as a result of the new customer but socialize the costs to the entire system even though the system previously met those standards or requirements. If designed correctly, such a structure could enable advancement of clean energy, meet new customer needs, and ensure that existing customers are not unnecessarily bearing the large, lumpy burdens caused by new customers.

Q. Has the Commission previously made findings that support the notion that these new large load customers should be thought of as a new and different class of customers?

A. Yes. The Commission adopted Staff's recommendation in Order No. 18-031 to conclude that it had legal authority to consider different transition adjustments for new direct access load. The Commission subsequently developed rules for NLDA in Order No. 18-341 and approved tariffs for PGE and PacifiCorp with terms and conditions that differ between long-term DA and NLDA. As the Commission has previously found, the terms and conditions of direct access service could be differentiated as a function of the new load characteristic. The same differentiation supports a potential cost of service framework for these new loads.

Q. Would this still be a cost of service-based tariff?

A. Yes. The new load would bear the costs of the associated energy and RA needs on a cost of service basis. The difference is that new targeted types resources could be acquired to meet customer needs, such as clean and/or renewable energy. As the Commission has acknowledged previously, and we agree, all customers should support RA and pay reasonable charges for this service.

Q. Could this construct also be used to further efforts of customers to decarbonize faster than PGE's overall portfolio?

A. Possibly. While the Commission has approved both the first and second tranche of PGE's Green Energy Affinity Rider (GEAR) rider, customer demand for opportunities to decarbonize will likely outstrip available capacity in the near term. A new load cost of service framework could effectively allow the customers to achieve a greater level of decarbonization for their service at a pace that could potentially be faster that PGE's overall portfolio, but such a framework also has the potential to ensure that PGE's overall portfolio is able to decarbonize more quickly by mitigating the impacts of new large loads. Further, if designed appropriately, such a framework should be able to meet the requirements established by the Commission to ensure that cost shifting to other customers is minimized or properly addresses using ratemaking.

Q. Is PGE asking the Commission to make any finding in the context of this GRC regarding new load cost of service?

A. No. However, we reiterate the importance of an established RA framework as enabling the further development of this concept and we also invite stakeholder feedback to improve the value of the offering while maintaining fairness to all customers.

B. Decoupling

Q. Please describe PGE's Schedule 123 Decoupling Mechanism.

A. For Schedules 7, 32 and 83, the Sales Normalization Adjustment (SNA) 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. The difference is accumulated in a balancing account and refunded or collected over a future period.

The Lost Revenue Recovery Adjustment (LRRA) component of Schedule 123 is a limited revenue recovery mechanism tied to the reduced kWh sales resulting from incremental Energy Efficiency (EE) savings generated through ETO programs directed to nonresidential customers other than Schedule 32. The LRRA applies to PGE nonresidential customers other than Schedule 32 whose load do not exceed one average megawatt at a Point of Delivery during the prior calendar year and those nonresidential customers who qualify as Self-Directing Customers.

To mitigate customer impacts, a 2% annual limiter applies to Schedule 123 rate revisions that result in a rate increase to the applicable SNA or LRRA rate schedule. Rate revisions resulting in a rate decrease are not subject to the 2% limit.

Q. Do you propose to continue Schedule 123, Decoupling Adjustment?

A. Yes. We propose to continue Schedule 123 which aligns customer and PGE interests in pursuing energy efficiency. In order for PGE to continue the mechanism, PGE must request an extension either by separate filing or as part of a general rate filing. With this filing we are requesting the extension of Schedule 123 thru December 31, 2025.

Q. What structural changes in Schedule 123 Decoupling do you propose for 2022?

A. We propose the following modifications to Schedule 123:

- Apply the SNA to Schedules 38/538, 47, and 49/549;
- Keep the 2% limiter but include the ability to balance any amounts over 2% to the subsequent year or years.

Q. Why do you propose to apply the SNA to Schedule 38/538, 47, and 49/549?

A. We propose this in order to align the schedules included in the SNA. The SNA will then cover all customers 200 kW or less other than lighting.

Currently, Schedules 7, 32, and 83 are included in the SNA. Schedule 38 is an optional schedule for large nonresidential customers served under Schedule 83, both covering customers with facility capacity from 31 kW to 200 kW. Likewise, Schedules 47 and 49 are irrigation and drainage pumping schedules that are optional for nonresidential customers served on Schedules 32 and 83, respectively.

Q. Please describe the current 2% limiter.

A. The current 2% rate increase cap acts as a "circuit breaker" to minimize the risk that rate revisions to the SNA or LRRA mechanisms result in bill impacts greater than 2% in any particular year. However, there is no limiter applied to SNA revisions that result in a rate decrease. We propose to continue the 2% limit for customer protection but allow amounts in the balancing account that exceed the 2% limit to carry forward to the subsequent year (or years) for recovery.

Q. Why do you propose changes to the 2% limiter?

A. Customer energy usage can change dramatically depending on the changes in expectation of the economy risk. A 2% limiter without a carryover creates an unbalanced risk and benefits sharing between shareholders and customers. Typically, when a rate limit is imposed, if the formulaic increase exceeds the limit, the utility will be able to carry over any uncollected revenues until the next rate adjustment. Consistent with the goals of revenue regulation, it is important for reducing the risk that the utility will not recover its revenue requirements by allowing the carryover. Allowing excess balances that are a charge to customers to be carried forward creates a balance between shareholders and customers while reasonably manage the price impacts. In addition, the 2% provision does not apply to credits due to decoupling. Any charge in one year in excess can net against credits in future years, which can stabilize price impacts as well.

Q. What changes in Schedule 123 prices do you presume for 2022?

A. For the SNA portion of Schedule 123, we provide a preliminary estimate of the Schedule 123 prices that include activity through the January 2021 billing cycle. For Schedule 7, the anticipated charge in Schedule 123 will result in a $30 million decrease in revenues from the current Schedule 123 charge designed to collect approximately $13.5 million from Schedule 7 customers during 2021 (based on 2019 results). We estimate a refund of approximately $16 million in 2022 (based on 2020 results).

For Schedule 32, the anticipated charge in Schedule 123 will result in a $2.4 million increase in revenues from the current Schedule 123 charge designed to collect $1.5 million from Schedule 32 customers. We estimate a collection of approximately $4 million in 2022 based on 2020 results. The 2020 decoupling results for Schedule 32 customers is $10 million and limited materially by the 2% limit.

For Schedule 83, the anticipated charge in Schedule 123 will result in a $2.9 million increase in revenues from the current Schedule 123 charge designed to collect $2.7 million from Schedule 83 customers. We estimate a collection of approximately $5.7 million in 2022 based on 2020 results. The 2020 decoupling results for Schedule 83 customers is $7.8 million and limited materially by the 2% limit. We presume that the LRRA portion of Schedule 123 will be at the same level as current. The estimated change in Schedule 123 prices results in a decrease in revenues. This filing doesn't include the impact of the balance above the 2% limit for Schedule 32 and Schedule 83.

Q. How much revenue recovery will be disallowed for PGE by the 2% limiter?

A. PGE expects that a total of $8.2 million will be disallowed in 2022 because the decoupling balance will go over the 2% limit in Schedule 32 and Schedule 83. Small and large nonresidential customers electric usage dropped to an unexpected low level due to recent pandemic. The protracted lockdowns caused loss of demand from both commercial and industrial sectors. A prolonged period of decreased demand and economic downturn is expected by unanticipated and extended constraints on economic activity. Various costs that are being incurred by utilities during this pandemic have already caused financial burden to PGE, including collection shortfalls, continuing service to non-paying customers, and operational burdens from managing a distributed workforce, all while providing uninterrupted service during a period of significant constraints. PGE expects this revenue shortfall will continue to increase as the nation works through the pandemic and allowing carryover of any balance over the 2% limit to the future will help PGE's revenue outlook and is especially important during this critical time.

C. Schedule 137

Q. What changes do you propose for Schedule 137 in 2022?

A. We propose to include all customers in cost recovery as those programs are directed by legislation in furtherance of Oregon's decarbonization public policy. Currently this schedule recovers costs from COS customers and nonresidential customers that opt out of COS for the short term. It does not recover costs from long-term or new load direct access customers.

Q. What costs is Schedule 137 designed to recover?

A. Schedule 137 recovers costs associated with the Solar Payment Option (SPO), a solar incentive program mandated by statute and closed to new participation.

Q. Why do you propose to recover costs from all customers?

A. To the extent that the SPO elicits any system benefits that accrue to LTDA and NLDA customers, those direct access customers are bypassing the associated costs. And, as the program is legislatively mandated for the broader public good, all customers should support it. Governor Brown's Executive Order, EO 20-04, directs the Commission to decarbonize the utility sector. It works a fundamental unfairness that customers on long term and new load opt out, do not contribute to the costs of these mandated programs, thus shifting costs onto cost of service customers. In addition, the SPO is similar to Community Solar. Commission Order No. 20-173 enabled PGE to recover costs of Community Solar from all customers with DA priced at COS. PGE requests the same treatment for SPO.

D. New Schedules 138 and 150

Q. What new cost recovery schedules are you introducing?

A. PGE is introducing new schedules to recover costs associated with energy storage and transportation electrification not otherwise included in customer prices. Since 2020 costs associated with PGE's Residential Battery Energy Storage Pilot have been deferred. The Commission approved PGE's annual applications for deferral of these pilot costs. PGE estimates that through the end of 2021, approximately $0.7 million will be deferred for Energy Storage. Pursuant to the stipulation adopted by Commission Order No. 20-279, PGE may also request to recover other energy storage projects via the new schedule.

Transportation electrification cost recovery has been approved by the Commission and deferral accounts started to cumulate in 2018. The total recovery from this newly introduced schedule will be about $2.5 million in 2022.

Q. What allocation methodologies do you propose?

A. For energy storage, we propose to allocate based on generation revenues. For transportation electrification, we propose to allocate based on revenues, with direct access priced at cost of service, similar to the allocation methodology for Schedule 136, Community Solar. For transportation electrification, customers who opt out of COS will pay the same amount as a similarly situated customer on COS.

E. Schedule 300

Q. Please describe PGE's Schedule 300.

A. Schedule 300 – Charges as Defined by the Rules and Regulations and Miscellaneous Charges is a schedule designed to directly assign and charge costs to customers who request services that are not generally within the normal operations of PGE's business or specifically benefit the requesting customer. Some examples may include reconnection or disconnection (for a reason other than safety), temporary electrical service, or the rental of equipment such as transformers. When these services are requested, the costs are assigned directly to the requesting customer. This direct application of cost-causation is consistent with Bonbright's principles of rate design, previously discussed in this testimony.

Q. Please describe the changes to Schedule 300 that PGE is requesting.

A. PGE is requesting Schedule 300 price changes as follows:

- Line extension allowances (Rule I) – PGE's Commercial Line Extension Allowances (LEA) were last updated in 2011 and PGE's Residential Line

Extension Allowances were updated at the end of 2020, based on the Basic and Distribution Charge Revenues from UE 335. PGE proposes to update all rate schedules using the proposed Basic and Distribution Charges for each Schedule contained in Exhibit 1208.

- The current and proposed Line Extension Allowances updates are shown in Table 9 below:

Table 9
Current and Proposed Commercial Line Extension Allowances

Schedule	Current	Proposed	Units
Schedule 7-Primary Other	$2,260.00	$1,867	dwelling unit
Schedule 7-All Electric	$1,590.00	$2,660	dwelling unit
Sch 32	$0.1473	$0.2637	estimated annual kWh
Sch 38, 83	$0.0780	$0.1082	estimated annual kWh
Sch 85 & 89 Secondary	$0.0531	$0.0791	estimated annual kWh
Sch 85 & 89 Primary	$0.0264	$0.0474	estimated annual kWh
Sch 15, 91 & 95	$0.0850	$0.1992	estimated annual kWh
Sch 92	$0.0531	$0.0521	estimated annual kWh
Sch 47 & 49	$0.0336	$0.0995	estimated annual kWh

- Consistent with past practice that calculates the Line Extension Allowance using the Company's proposed Basic and Distribution Charge revenues and applying a Revenue multiplier, PGE employed the same methodology to update its proposed Line Extension Allowances. PGE is applying the previous Commercial Line Extension Allowance Revenue Multipliers that were used in 2011 and the Residential Line Extension Revenue Multiplier that was used in Advice no. 20-14 to the proposed Basic and Distribution Charge revenues to calculate the proposed Line Extension Allowance amounts for 2022. Exhibit 1208 contains PGE's proposed Line Extension Allowance calculations and the maximum supportable allowable revenue multiplier calculation for each rate schedule based on the marginal costs to serve each customer class. The supportable Line Extension Allowances are much higher than PGE is proposing.

- Service of Limited Duration (Rule L) rates for Standard Temporary Service have been updated to reflect current costs. PGE's proposed Standard Temporary Service proposed price calculations are shown in Table 10 below:

Table 10
Current and Proposed Temporary Service Prices

Rate Type	Current Price	Proposed Price
Metered Temp - No Perm Service	$795	$1,077
Metered Temp - Existing Service	$260	$819
Metered Temp OH - Perm Service	$490	$607
Metered Temp UG - Perm Service	$450	$632
Enhanced Temporary Service (Gold-Temp) Unmetered Fixed Feed	$430	$865

The increase in PGE's Standard Temporary Service rates is reflective of its 2022 forecasted labor costs. In addition to the updated labor costs for Enhanced Temporary Service (Gold-Temp) PGE has updated the Estimated Energy Cost for Enhanced Temporary Service (Gold-Temp). Previously PGE estimated the Estimated Energy Cost of $30.00 which was based on the following assumptions. 20 amps @ 4 hours per day x 30 days=288 kWh x 10.605 (Sch 32). Based on the average new home construction time and how long the Enhanced Temporary Service pedestal is deployed in the field, PGE has updated the Estimated Energy Cost to $354.07. This is based on the following assumptions. 20 amps @ 6 hours per day x 180 days =2,592 kWh x 13.66 (proposed Sch 32 rate). Lastly, PGE is proposing to update the Enhanced Temporary Service fixed fee from a 12-month period to a 6-month period with the option to extend for an additional 6- month time period at the estimated energy cost for up to 24 months.

F. Rules and Regulations

Q. Please describe the changes to Rules and Regulations that PGE is requesting?

A. PGE is requesting the following Rules and Regulation changes

- Definitions (B), PGE has added definitions for Multi-Family and Single-Family Residential dwellings.
- Conditions Governing Customer Attachment to Facilities (Rule C) - PGE has updated its Service Restoration language for
    - A major outage event such as a major storm.
    - Removed radio and television stations, newspapers and telephone exchanges language and replaced by emergency media communications.
    - Aligned the descriptions of the restoration practices.
- Line Extensions (Rule I) - expanding the requirement reviews to any line extension projects that equal or exceed $250,000 in order to protect existing customers' financial interests as well as to allow flexible payments.
- Special Types of Electricity Service (Rule L) - updated the Enhanced Temporary Service time period from 12 months to 6 months with the option to renew for up to 24 months.

G. Schedule 108, Public Purpose Charge

Q. What changes do you propose for Schedule 108?

A. We propose to update Special Condition 1 to require ESSs at the same time they remit monthly to the Company the PPC it collects from their Customers to also provide the calculations of the PPC for each Service Point enrolled in Direct Access. PGE is making this change so the Company can correctly allocate the applicable portions of the Direct Access Self Directing Customer's monthly PPC.

H. Schedule 146, Colstrip Power Plant Operating Life Adjustment

Q. Please describe Schedule 146.

A. Schedule 146 was established in 2017 as an automatic adjustment clause as defined in ORS 757.210 to collect PGE's share of incremental accelerated depreciation and decommissioning costs associated with the change in Colstrip's assumed end of depreciable life from year-end 2042 to 2030 as specified Oregon Senate Bill 1547, Section 1. Upon PGE's incorporation of the incremental accelerated depreciation and decommissioning costs into base rates with PGE's 2018 test year rate case, Schedule 146 prices were subsequently set to zero.

Q. What changes do you propose for Schedule 146?

A. PGE proposes to isolate all identifiable Colstrip-related costs (both expense and capital related costs), remove them from PGE's base rate schedules and include them for recovery within PGE's Schedule 146. The change allows PGE to update the Colstrip related revenue requirement annually, instead of periodically through a general rate case, pursuant to an automatic adjustment clause. Furthermore, similar to the original design of Schedule 146, we propose only the changes to Colstrip's operating life and decommissioning costs are allowed to be updated annually. All other Colstrip costs could only be updated upon 1) the removal of Colstrip from regulated service or through existing mechanisms, or 2) rate change requests as allowable through Oregon Revised Statutes and Oregon Administrative Rules (e.g., through a general rate case).

VIII. Line Losses

Q. Have you performed an update to the current line loss study?

A. Yes. The overall estimate of percentage line losses has decreased slightly, by approximately three-tenths of one percent. PGE Exhibit 1208 summarizes how losses are allocated to customers segments by delivery voltage. The methodology used in this update allows for more granular loss estimates, enabling greater precision for loss estimates by time of year or time of day. The detailed calculations and data used to develop the line loss percentages are contained in the Pricing work papers.

Q. How do you use the line loss percentages?

A. The line loss percentages are an input to the busbar load forecast. In addition, these percentages are used for marginal cost of generation estimates and in energy pricing for variable price option customers. The internal loss percentages are used by ESSs for scheduling energy to deliver to PGE's service territory. These losses are contained in Schedule 600.

IX. 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 Interim Manager, Pricing and Tariffs since January of 2018. 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, OR, where I developed, prepared, and reviewed financial analyses used in securities litigation.

Q. Ms. Tang, please state your educational background and qualifications.

A. I received a Master of Art degree in Economics from University of California, Davis and a Master of Science degree in Statistics from Portland State University. I joined PGE's Rates and Regulatory Affairs department in 2020. In my current role, I am responsible for the preparation of rate design and related analyses. Prior to joining PGE, I was a regulatory consultant at PacifiCorp since 2008, working in various areas, including regulation, net power cost, production cost modeling, and load forecasts for six states in PacifiCorp's service territory.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

SCHEDULE 7
RESIDENTIAL SERVICE

PURPOSE

This schedule provides Standard and Optional Service choices for residential customers. Optional Services include a time of use (TOU) portfolio option, Peak Time Rebate, and Green Future[SM] renewable portfolio options.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

DEFINITIONS

Peak Time Rebate (PTR) Program – Customers choosing the 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. See details below.

ENERGY PRICE PLANS (DEFAULT PLAN AND TIME-OF-USE PORTFOLIO OPTION)

RESIDENTIAL SERVICE PRICE PLAN (DEFAULT PLAN)

This default plan is provided to Residential Customers who do not choose the TOU Portfolio option price plan.

Monthly Rate

The default plan is priced as the totals of the following charges per Service Point (SP)*, **:

Basic Charge			**(C)**
Single-Family Home	$12.50		|
Multi-Family Home	$8.00		**(C)**
Transmission and Related Services Charge	0.601	¢ per kWh	**(I)**
Distribution Charge	5.651	¢ per kWh	**(I)**
Energy Charge**			
First 1,000 kWh	6.636	¢ per kWh	**(I)**
Over 1,000 kWh	6.996	¢ per kWh	**(R)**

* See Schedule 100 for applicable adjustments.
** As defined in Section Rule B of this tariff.

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: DEFAULT PLAN (Continued)

Peak Time Rebate Event Participation

Residential Customers on the default plan can also enroll and participate in PTR events. 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 on the default plan plus PTR will pay the default 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 8:00 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.

Special Conditions Related to Peak Time Rebate Options **(M)**

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. **(M)**

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: DEFAULT PLAN (Continued)
Special Conditions Related to Peak Time Rebate Options (Continued **(T)** **(M)**

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.

TIME-OF-USE PORTFOLIO OPTION (WHOLE PREMISES OR ELECTRIC VEHICLE CHARGING) (Enrollment is necessary)

This option provides TOU pricing for transmission and related services, distribution and energy*.

Monthly Rate

Basic Charge			(C)
Single-Family Home	$12.50		
Multi-Family Home	$8.00		(C)
On-Peak Charge	34.900	¢ per kWh	(I)
Transmission and Related Services	2.000	¢ per kWh	
Distribution	17.100	¢ per kWh	
Energy	15.800	¢ per kWh	
Mid-Peak Charge	11.900	¢ per kWh	
Transmission and Related Services	0.520	¢ per kWh	
Distribution	4.980	¢ per kWh	
Energy	6.400	¢ per kWh	
Off-Peak Charge	7.234	¢ per kWh	
Transmission and Related Services	0.250	¢ per kWh	
Distribution	2.796	¢ per kWh	
Energy	4.188	¢ per kWh	(I)
Over 1,000 kWh block adjustment**	0.360	¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.
** Not applicable to separately metered Electric Vehicle (EV) TOU option.

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: TOU PORTFOLIO OPTION (Continued)

On- and Off-Peak Hours

On-Peak	5:00 p.m. to 9:00 p.m. Monday-Friday
Mid-Peak	7:00 a.m. to 5:00 p.m. Monday-Friday;
Off-Peak	9:00 p.m. to 7:00 a.m. Monday-Friday;
	All day. Saturday, Sunday and holidays

Note: For Customers with Non-Network Meters, the time periods set forth above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November. Customers with Network Meters will observe the regular daylight-saving schedule.

Holidays are as follows: New Year's Day on January 1; Memorial Day, the last Monday in May; Independence Day on July 4; Labor Day, the first Monday in September; Thanksgiving Day, the fourth Thursday in November; and Christmas Day on December 25. If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

LEGACY TIME-OF-USE PORTFOLIO OPTION (WHOLE PREMISES OR ELECTRIC VEHICLE CHARGING)

This option provides TOU pricing for transmission and related services, distribution and Energy*.

Monthly Rate

Basic Charge			**(C)**
Single-Family Home	$12.50		|
Multi-Family Home	$8.00		**(C)**
Transmission and Related Services Charge TOU Portfolio			
On-Peak Period	0.986	¢ per kWh	**(I)**
Mid-Peak Period	0.986	¢ per kWh	**(I)**
Off-Peak Period	0.000	¢ per kWh	
Distribution Charge TOU Portfolio			
On-Peak Period	9.267	¢ per kWh	**(I)**
Mid-Peak Period	9.267	¢ per kWh	**(I)**
Off-Peak Period	0.000	¢ per kWh	
Energy Charge TOU Portfolio			
On-Peak Period	12.355	¢ per kWh	**(I)**
Mid-Peak Period	6.996	¢ per kWh	**(R)**
Off-Peak Period	4.119	¢ per kWh	**(R)**
First 1,000 kWh block adjustment**	(0.360)	¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.
** Not applicable to separately metered Electric Vehicle (EV) TOU option.

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	0.312	¢ per kWh	**(I)**
Distribution Charge	7.187	¢ per kWh	**(I)**
Cost of Service Energy Charge	4.772	¢ per kWh	**(R)**

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate (1) Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$12.44(2)	(I)
	400	21,000	147	22.83(2)	(I)
	1,000	55,000	374	50.63(2)	(I)
HPS	70	6,300	30	8.31(2)	(I)
	100	9,500	43	9.61	(R)
	150	16,000	62	12.00	
	200	22,000	79	14.51	(I)
	250	29,000	102	16.95	(I)
	310	37,000	124	19.85(2)	(I)
	400	50,000	163	24.62	(R)
Flood, HPS	100	9,500	43	9.66(2)	(I)
	200	22,000	79	15.32(2)	(I)
	250	29,000	102	18.26	(I)
	400	50,000	163	25.74	(I)
Shoebox, HPS (bronze color, flat	70	6,300	30	8.57	(R)
lens or drop lens, multi-volt)	100	9,500	43	10.62	(R)
	150	16,500	62	13.34	(I)
Special Acorn Type, HPS	100	9,500	43	13.45	(I)
HADCO Victorian, HPS	150	16,500	62	15.78	(I)
	200	22,000	79	18.18	(I)
	250	29,000	102	20.92	(I)
Early American Post-Top, HPS					
Black	100	9,500	43	10.50	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire(1)		
Special Types						
Cobrahead, Metal Halide	150	10,000	60	$12.11	**(R)**	
	175	12,000	71	13.71	**(I)**	
Flood, Metal Halide	350	30,000	139	23.81	**(I)**	
	400	40,000	156	24.19	**(I)**	
Flood, HPS	750	105,000	285	43.16	**(I)**	
HADCO Independence, HPS	100	9,500	43	14.55	**(I)**	
					(D)	
Alternative Special Acorn, Techtra	165	12,000	60	26.06	**(N)**	
HADCO Capitol Acorn, HPS	100	9,500	43	17.17	**(I)**	
						(D)
	200	22,000	79	21.82	**(I)**	
	250	29,000	102	15.97	**(R)**	
HADCO Techtra, HPS	100	9,500	43	21.24	**(R)**	
	150	16,000	62	24.33	**(I)**	
						(D)
HADCO Westbrooke, HPS	70	6,300	30	14.92	**(I)**	
	100	9,500	43	16.67	**(I)**	
						(D)
	250	29,000	102	22.47	**(R)**	
Holophane Mongoose, HPS	150	16,000	62	17.89	**(I)**	

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Acorn					
LED	>35-40	3,262	13	$8.43	(C)
	>40-45	3,500	15	6.99	
	>45-50	5,488	16	11.39	
	>50-55	4,000	18	7.37	
	>55-60	4,213	20	6.85	
	>60-65	4,273	21	9.48	
	>65-70	4,332	23	14.20	
	>70-75	4,897	25	7.60	
HADCO LED	70	5,120	24	16.44	(C)
Roadway LED	>25-30	3,470	9	13.81	(C)
	>30-35	2,530	11	4.01	
	>35-40	4,245	13	4.57	
	>40-45	5,020	15	7.68	
	>45-50	3,162	16	4.59	
	>50-55	3,757	18	5.08	
	>55-60	4,845	20	8.79	
	>60-65	4,700	21	9.89	
	>65-70	5,050	23	5.90	
	>70-75	7,640	25	14.46	
	>75-80	8,935	26	9.07	
	>80-85	9,582	28	7.67	
	>85-90	10,230	30	9.85	
	>90-95	9,928	32	8.30	
	>95-100	11,719	33	8.42	
	>100-110	7,444	36	7.86	
	>110-120	12,340	39	9.74	
	>120-130	13,270	43	10.23	
	>130-140	14,200	46	11.44	
	>140-150	15,250	50	11.15	
	>150-160	16,300	53	19.12	
	>160-170	17,300	56	11.88	
	>170-180	18,300	60	13.95	
	>180-190	19,850	63	12.75	
	>190-200	21,400	67	15.11	(C)

(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	12.46	(C)
	53	5,079	18	15.73	
	69	6,661	24	16.59	
	85	8,153	29	17.72	
Pendant LED (Flare)	>35-40	3,369	13	12.75	
	>40-45	3,797	15	8.79	
	>45-50	4,438	16	8.91	
	>50-55	5,079	18	16.19	
	>55-60	5,475	20	14.03	
	>60-65	6,068	21	14.16	
	>65-70	6,661	23	17.52	
	>70-75	7,034	25	14.68	
	>75-80	7,594	26	16.31	
	>80-85	8,153	28	18.32	(C)
CREE XSP LED	>20-25	2,529	8	$3.24	(C)(M)
	>30-35	4,025	11	14.17	
	>40-45	3,819	15	4.10	
	>45-50	4,373	16	4.46	
	>55-60	5,863	20	4.75	
	>65-70	9,175	23	16.66	
	>90-95	8,747	32	6.56	
	>130-140	18,700	46	19.53	(C)(M)

(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]	
Post-Top, American Revolution LED	>30-35	3,395	11	5.43	**(C)(M)**
	>45-50	4,409	16	6.36	
Flood LED	>80-85	10,530	28	14.70	
	>120-130	16,932	3	8.31	
	>180-190	23,797	63	19.04	
	>370-380	48,020	127	27.00	**(C)(M)**

Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$5.32	**(I)(M)**
	40 to 55	$6.31	
Wood, Painted for Underground	35 or less	$5.32 [3]	**(I)**
Wood, Curved Laminated	30 or less	$6.32 [3]	**(R)**
Aluminum, Regular	16	$4.07	
	25	$7.59	
	30	$8.76	
	35	$10.19	
Aluminum, Fluted Ornamental	14	$7.31	
Aluminum, Fluted Ornamental	16	$7.59	**(R)**
			(D)

(1) See Schedule 100 for applicable adjustments.
(2) No pole charge for luminaires placed on existing Company-owned distribution poles.
(3) No new service. **(M)**

SCHEDULE 15 (Continued) **(T)**

MONTHLY RATE (Continued)

Rates for Area Light Poles[(1)]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Aluminum Davit	25	$8.12	(R)(M)
	30	$9.19	
	35	$10.55	
	40	$13.58	
Aluminum Double Davit	30	$10.23	
Aluminum, Smooth Techtra Ornamental	18	$16.08	
Aluminum, Fluted Westbrooke	18	$15.09	(R)
Aluminum, Non-fluted Ornamental, Pendant	22	$14.99	(C)
Fiberglass Fluted Ornamental; Black	14	$9.82	
Fiberglass, Regular			
Black	20	$4.41	
Gray or Bronze	30	$7.16	
Black, Gray, or Bronze	35	$7.05	
Fiberglass, Anchor Base, Gray or Black	35	$9.71	
Fiberglass, Direct Bury with Shroud	18	$5.97	(C)(M)

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 **(M)**

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. **(M)**

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 26 (Continued)

QUALIFIED LOAD REDUCTION (Continued)

If the Customer fails to deliver a minimum of 70% of the Committed Load Reduction on average during an event for which the Customer is enrolled during events in that month, the Customer is not eligible for the Energy Reduction Payment for that Event and the Reservation Payment for that month. If other Load Reduction Events are called in the same month, and the Customer complies, the corresponding Energy Reduction Payments are paid for each 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 Customer's Qualified Load Reduction (kW) 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. 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.

ENERGY PAYMENTS

The Energy Payment is 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 commitment.

The monthly energy prices (per MWh) for the months in which the events are called* are:

Jan 2022	Feb 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Nov 2022	Dec 2022
$43.00	$38.00	$18.00	$42.50	$57.00	$49.00	$32.26	$40.41

(C)
(I)(R)

The Firm Energy Reduction Payment rates will be updated by December 1st for the next year beginning in January. Evaluation and settlement of the Firm Energy Reduction Payment will occur within 60 days of the Firm Load Reduction Event.

* PGE will not call events on Saturdays, Sundays, or Holidays. Holidays are New Year's Day (January 1), President's Day (third Monday of February), 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 holiday. If a holiday falls on Sunday, the following Monday is designated a holiday.

SCHEDULE 26 (Continued)

LINE LOSSES

Losses will be included by multiplying the applicable price by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

LOAD REDUCTION MEASUREMENT

Load reduction is measured as a reduction of Demand from a customer baseline load calculation during each hour of the Load Reduction Event. Although the Agreement 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 Event if the Event starts at 11 am or later. This adjustment is the difference between the Event day load and the average load of the five highest days used in the load profile above during the two-hour period ending four hours prior to the start of the Event.

Typical Operational Days

Typical Operational Days exclude days that a Customer has participated in a Firm Load Reduction Event or pre-scheduled opt-out days as defined in the Special Conditions. Typical Operational Days for the baseline 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.

The Company may decline the Customer's enrollment application when 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 Demand 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 Events Season.

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	$20.00		
Three Phase Service	$29.00		
Transmission and Related Services Charge	0.479	¢ per kWh	(I)
Distribution Charge			
First 5,000 kWh	5.408	¢ per kWh	(I)
Over 5,000 kWh	1.329	¢ per kWh	(R)
Energy Charge Options			
Standard Service	5.735	¢ per kWh	(R)
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.040	¢ per kWh	(R)
Mid-Peak Period	5.735	¢ per kWh	(R)
Off-Peak Period	3.349	¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

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 0.305¢ per kWh for wheeling **(R)**
- times a loss adjustment factor of 1.0640 **(R)**

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 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	$30.00		
Transmission and Related Services Charge	0.425	¢ per kWh	**(I)**
Distribution Charge	7.142	¢ per kWh	**(I)**
Energy Charge*			
On-Peak Period	5.971	¢ per kWh	**(R)**
Off-Peak Period	4.471	¢ per kWh	**(R)**

* 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)

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 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0640	**(R)**

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 (30) 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.

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**	$37.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.489	¢ per kWh	**(I)**
Distribution Charge			
First 50 kWh per kW of Demand***	13.040	¢ per kWh	**(I)**
Over 50 kWh per kW of Demand	11.040	¢ per kWh	**(I)**
Energy Charge	6.384	¢ per kWh	**(R)**

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 10 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 49
LARGE NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Large Nonresidential Customer is defined as having a monthly Demand exceeding 30 kW at least twice within the preceding 13 months, or with seven months or less of service having exceeding 30 kW once.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge			
Summer Months**	$45.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.493	¢ per kWh	**(I)**
Distribution Charge			
First 50 kWh per kW of Demand***	9.917	¢ per kWh	**(I)**
Over 50 kWh per kW of Demand	7.917	¢ per kWh	**(I)**
Energy Charge	6.566	¢ per kWh	**(R)**

* 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 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	$5,380.00	$3,630.00	$5,680.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$1.86	$1.84	$1.81	(I)
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	(R)
Over 4,000 kW	$1.04	$1.03	$1.03	(R)
per kW of monthly On-Peak Demand	$1.60	$1.58	$0.50	(R)
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	0.252 ¢	0.251 ¢	0.249 ¢	(I)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

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 0.305¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, plus losses. **(R)**

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	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

A Customer served under this schedule may elect to receive Direct Access Partial Requirements Service from an Electricity Service Supplier (ESS) under the terms of Schedule 575 provided it has given notice consistent with any Baseline Energy option requirements. A Customer may return to Schedule 75 provided it has met any term requirements of Schedule 575 and any requirements needed to purchase Baseline Energy if needed.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Transmission, Distribution, Demand and Generation Contingency Reserves Charges, when applicable. In addition, the Company may require a higher Minimum Charge, if necessary, to justify the Company's investment in service Facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:*

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Transmission and Related Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.062	$0.062	$0.019	**(I)(R)**
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.072	$0.072	$0.071	**(R)(I)**
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)

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 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported. **(R)**

Daily ERP: The Daily ERP Energy Charge will be determined in accordance with a commodity energy price quote from the Company accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.305¢ per kWh for wheeling, plus losses. Customer will communicate with PGE between hour 0615 and 0625 to receive the PGE commodity energy price quote based on the customer's submitted ENF for the day of delivery. Customer will state acceptance of quote within 5 minutes of receipt of quote from the Company. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place. **(R)**

Monthly ERP: The Monthly ERP Energy Charge will be determined in accordance with a price quote accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.305¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. **(R)**

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ERP Pricing (Continued)

The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

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	(I)
Primary Delivery Voltage	1.0530	(I)
Secondary Delivery Voltage	1.0640	(R)

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 0.305¢ per kWh for wheeling, plus losses. **(R)**
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the Powerdex-Mid-C Hourly Index plus 0.305¢ per kWh for wheeling, plus losses. **(R)**

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

For any Imbalance Energy in any hour in excess of 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 10%, plus 0.305¢ per kWh for wheeling, plus losses. **(R)**

For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the Powerdex-Mid-C Hourly Index, less 10%, plus 0.305¢ per kWh for wheeling, **(R)** plus losses.

The Imbalance Settlement Amount may be a credit or charge in any hour.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

In all territory served by the Company. The Company may restrict Customer loads returning to this schedule in accordance with Rule N Curtailment Plan and Rule C (Section 2).

APPLICABLE

To existing Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule.

MONTHLY RATE

All charges for Emergency Default Service except the energy charge will be billed at the Customer's applicable Standard Service rate schedule for five business days after the Customer's initial purchase of Emergency Default Service.

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh **(R)** 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	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. Service under this Schedule is available for Secondary Delivery Voltage only.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge		
Single Phase Service	$35.00	
Three Phase Service	$45.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$1.86	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$5.12	**(I)**
Over 30 kW	$5.02	**(I)**
per kW of monthly On-Peak Demand	$1.60	**(R)**
Energy Charge (per kWh)		
On-Peak Period***	6.200 ¢	**(R)**
Off-Peak Period***	4.700 ¢	**(R)**
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.864 ¢	**(I)**

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 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 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage 1.0640 **(R)**

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 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	$810.00	$760.00	(I)
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$1.86	$1.84	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.48	$3.45	(I)
Over 200 kW	$2.28	$2.25	(I)
per kW of monthly On-Peak Demand	$1.60	$1.58	(R)
Energy Charge (per kWh)			
On-Peak Period***	6.001 ¢	5.941 ¢	(R)
Off-Peak Period***	4.501 ¢	4.441 ¢	(R)
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.308 ¢	0.306 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 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.

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.

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 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

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.

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	$5,380.00	$3,630.00	$5,680.00	**(I)**
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$1.86	$1.84	$1.81	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	**(R)**
Over 4,000 kW	$1.04	$1.03	$1.03	**(R)**
per kW of monthly On-Peak Demand	$1.60	$1.58	$0.50	**(R)**
Energy Charge (per kWh)				
On-Peak Period***	5.914 ¢	5.856 ¢	5.797 ¢	**(I)**
Off-Peak Period***	4.414 ¢	4.356 ¢	4.297 ¢	**(I)**
See below for Daily Pricing Option description.				
System Usage Charge				
per kWh	0.252 ¢	0.251 ¢	0.249 ¢	**(I)**

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 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 0.305¢ per kWh for wheeling, plus **(R)** losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 90
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW and Aggregate to >30 MWa) **(C)**

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. **(C)**

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge	$20,900.00	**(I)**
Transmission and Related Services Charge per kW of monthly On-Peak Demand	$1.84	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.70	**(I)**
Over 4,000 kW	$1.39	**(I)**
per kW of monthly on-peak Demand	$1.58	**(R)**
Energy Charge (per kWh)		
Usage (30MWa – 250MWa)		**(C)**
On-Peak Period***	5.652¢	**(N)**
Off-Peak Period***	4.152¢	**(N)**
Usage (greater than 250MWa)		
On-Peak Period***	5.539¢	**(I)**
Off-Peak Period***	4.039¢	**(I)**
See below for Daily Pricing Option description.		
System Usage Charge		
Usage (30MWa – 250MWa) per kWh	0.100¢	**(C)**
Usage (greater than 250MWa) per kWh	0.098¢	**(C)**

* 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 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 91 (Continued)

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.329 ¢ per kWh	**(I)**
Distribution Charge	7.170 ¢ per kWh	**(I)**
Energy Charge		
Cost of Service Option	4.839 ¢ per kWh	**(R)**

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 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. **(R)**

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0640. **(R)**

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

Enrollment for Service

To begin service under the Daily Price Option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING

High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead Power Doors **	70	6,300	30	*	$0.81	(R)
	100	9,500	43	*	0.93	
	150	16,000	62	*	0.81	
	200	22,000	79	*	0.97	
	250	29,000	102	*	0.81	
	400	50,000	163	*	0.99	
Cobrahead	70	6,300	30	$4.71	1.10	
	100	9,500	43	4.41	1.05	
	150	16,000	62	4.47	1.06	
	200	22,000	79	5.11	1.13	
	250	29,000	102	4.72	1.07	
	400	50,000	163	4.91	1.10	
Flood	250	29,000	102	6.03	1.27	
	400	50,000	163	6.03	1.27	
Early American Post-Top	100	9,500	43	5.30	1.20	
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	4.97	1.15	(C)
	100	9,500	43	*	1.22	
	150	16,000	62	*	1.28	(R)(C)

* 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	Monthly Rates Option B		
Fiberglass, Black, Bronze, or Gray	20	$4.61	$0.17	(R)	(I)
Fiberglass, Black or Bronze	30	7.49	0.28	(I)	
Fiberglass, Gray	30	7.49	0.28	(R)	(I)
Fiberglass, Smooth, Black or Bronze	18	4.89	0.19	(I)	(I)
Fiberglass, Regular					
Black, Bronze, or Gray	18	$4.28	$0.16	(I)	(I)
	35	7.31	0.28	(R)	(I)
Aluminum, Regular with Breakaway Base	35	15.07	0.54	(N)	

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	$5.58	$0.21	**(I)**
Wood, Standard	40 to 55	6.57	0.25	**(I)**

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Acorn-Types						
HPS	100	9,500	43	$8.46	$1.67	**(R)**
HADCO Victorian, HPS	150	16,000	62	8.46	1.67	**(R)**
	200	22,000	79	8.78	1.72	**(R)**
	250	29,000	102	8.69	1.70	**(R)**
HADCO Capitol Acorn, HPS	100	9,500	43	12.17	2.23	**(I)(R)**
	150	16,000	62	*	2.19	**(C)(R)**
	200	22,000	79	*	2.27	**(C)(I)**
	250	29,000	102	*	0.89	**(C)(R)**
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	9.56	1.81	**(I)(R)**
	150	16,000	62	*	1.53	**(C)(R)**
HADCO Techtra, HPS	100	9,500	43	16.25	2.84	**(R)**
	150	16,000	62	17.01	2.96	**(I)(R)**
	250	29,000	102	*	2.73	**(C)(R)**
HADCO Westbrooke, HPS	70	6,300	30	11.53	2.11	**(I)(R)**
	100	9,500	43	11.67	2.13	**(I)(R)**
	150	16,000	62	*	2.42	**(C)(R)**
	200	22,000	79	*	0.95	**(C)(R)**
	250	29,000	102	10.24	1.91	**(R)**

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Types						
Flood, Metal Halide	350	30,000	139	*	$1.45	**(C)(R)**
Flood, HPS	750	105,000	285	$8.48	1.78	**(R)(R)**
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	Monthly Rates Option B	
Aluminum, Regular	25	$7.92	$0.30	**(R)**
	30	9.09	0.34	
	35	10.52	0.40	
Aluminum Davit	25	8.45	0.32	
	30	9.52	0.36	
	35	10.88	0.41	**(I)**
	40	13.97	0.53	**(I)**
Aluminum Double Davit	30	10.56	0.40	**(R)**

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	7.51	0.28	**(R)**
Aluminum, Smooth Techtra Ornamental	18	16.41	0.62	**(R)**
Aluminum, Fluted Ornamental	16	7.79	0.30	**(R)**
Aluminum, Double-Arm, Smooth Ornamental	18	12.65	0.48	**(R)(I)**
Aluminum, Fluted Westbrooke	18	15.42	0.58	**(R)**
Aluminum, Non-Fluted Ornamental, Pendant	22	15.32	0.58	**(C)(R)**
Fiberglass, Fluted Ornamental Black	14	10.51	0.40	**(R)(I)**
Fiberglass, Anchor Base, Gray or Black	35	9.98	0.38	**(R)**
Fiberglass, Anchor Base (Color may vary)	25	8.87	0.34	**(R)(I)**
	30	10.84	0.41	**(R)(I)**

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead, Metal Halide	150	10,000	60	*	$1.16	**(C)(R)**
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	$4.39	1.06	**(R)**
	250	10,000	94	*	*	
	400	21,000	147	5.08	1.10	**(R)**
	1,000	55,000	374	5.03	1.22	**(R)**
Holophane Mongoose, HPS	150	16,000	62	*	1.98	**(C)(R)**
	250	29,000	102	*	1.99	**(C)(I)**
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	5.36	*	**(R)**
Mercury Vapor	175	7,000	66	5.36	1.16	**(R)**

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Box, Anodized Aluminum						
Similar to GardCo Hub						
HPS - Twin	70	6,300	60	*	*	
HPS	70	6,300	30	*	*	
	100	9,500	43	*	$1.49	(R)
	150	16,000	62	*	0.89	(R)
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	0.90	(R)
	400	40,000	156	*	0.90	(R)
Cobrahead, Metal Halide	175	12,000	71	*	1.17	(R)
Flood, Metal Halide	400	40,000	156	$5.34	1.20	(R)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	0.89	(R)
100/150 Watt Ballast	100	9,500	43	*	0.89	(R)
100/150 Watt Ballast	150	16,000	62	*	0.89	(R)
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.33	(R)
	165	12,000	60	*	0.97	(I)
HADCO Techtra, QL	165	12,000	60	*	1.28	(C)(I)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	0.89	(R)
KIM Archetype, HPS	250	29,000	102	*	2.01	(R)
	400	50,000	163	*	2.45	(I)
Special Acorn-Type, HPS	70	6,300	30	8.36	1.57	(R)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Early American Post-Top, HPS						
Black	70	6,300	30	$5.14	$1.04	**(R)**
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	5.20	1.10	**(I)(R)**
Flood, HPS	70	6,300	30	4.45	1.09	**(R)**
	100	9,500	43	4.46	1.07	**(R)**
	200	22,000	79	5.92	1.16	**(R)**
Cobrahead, HPS						
Power Door	310	37,000	124	*	1.27	**(C)(R)**
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Fluorescent	28	N/A	12	*	*	

* Not offered.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	4.26	*	**(R)**
Aluminum, Painted Ornamental	35	*	*	**(C)**
Aluminum, Regular	16	4.26	0.16	**(R)**
Bronze Alloy GardCo	12	*	0.23	**(I)**
Concrete, Ornamental	35 or less	7.92	0.30	**(R)**
Fiberglass, Direct Bury with Shroud	18	6.30	0.24	**(R)**
Steel, Painted Regular **	25	7.92	0.30	**(R)**
Steel, Painted Regular **	30	9.09	0.34	**(R)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.41	**(I)**
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41	**(I)**
Wood, Laminated without Mast Arm	20	4.61	0.17	**(R)(I)**
Wood, Laminated Street Light Only	20	4.61	*	**(R)**
Wood, Curved Laminated	30	6.40	0.28	**(R)**
Wood, Painted Underground	35	5.58	0.21	**(I)**

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

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 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	0.366	¢ per kWh	(I)
Distribution Charge	1.869	¢ per kWh	(R)
Energy Charge	5.098	¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election (Continued)

1. 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	0.329 ¢ per kWh	**(I)**
Distribution Charge	7.170 ¢ per kWh	**(I)**
Energy Charge		
Cost of Service Option	4.839 ¢ per kWh	**(R)**

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 0.305¢ per kWh for **(R)**
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. **(R)**

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, PortlandGeneral.com/business

SCHEDULE 95 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate	Straight Time	Overtime
	$124.00 per hour	$155.00 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	$9.57	$0.41	(C)
	>25-30	3,470	9	4.49	0.41	
	>30-35	2,530	11	4.75	0.41	
	>35-40	4,245	13	4.50	0.41	
	>40-45	5,020	15	4.62	0.41	
	>45-50	3,162	16	4.72	0.41	
	>50-55	3,757	18	4.96	0.42	
	>55-60	4,845	20	4.63	0.41	
	>60-65	4,700	21	4.64	0.41	
	>65-70	5,050	23	5.16	0.43	
	>70-75	7,640	25	5.23	0.43	
	>75-80	8,935	26	5.24	0.43	
	>80-85	9,582	28	5.25	0.43	
	>85-90	10,230	30	5.21	0.43	
	>90-95	9,928	32	5.25	0.43	
	>95-100	11,719	33	5.25	0.43	
	>100-110	7,444	36	5.53	0.43	
	>110-120	12,340	39	5.26	0.43	
	>120-130	13,270	43	5.27	0.43	
	>130-140	14,200	46	6.09	0.45	
	>140-150	15,250	50	7.06	0.48	
	>150-160	16,300	53	6.99	0.48	
	>160-170	17,300	56	7.06	0.48	
	>170-180	18,300	60	6.88	0.47	
	>180-190	19,850	63	7.07	0.48	
	>190-200	21,400	67	7.18	0.48	(C)

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	$11.70	$0.61	**(C)**
	>40-45	3,500	15	11.79	0.61	
	>45-50	5,488	16	9.71	0.55	
	>50-55	4,000	18	11.80	0.61	
	>55-60	4,213	20	11.70	0.61	
	>60-65	4,273	21	11.81	0.61	
	>65-70	4,332	23	11.67	0.61	
	>70-75	4,897	25	11.70	0.61	
HADCO LED	70	5,120	24	15.58	0.72	**(C)(D)**
Pendant LED (Non-Flared)	36	3,369	12	13.08	0.65	**(R)(I)(C)**
	53	5,079	18	13.81	0.67	
	69	6,661	24	13.92	0.67	
	85	8,153	29	14.45	0.69	**(R)(I)** **(D)**
Pendant LED (Flared)	>35-40	3,369	13	13.24	0.65	**(C)**
	>40-45	3,797	15	13.35	0.65	
	>45-50	4,438	16	13.35	0.65	
	>50-55	5,079	18	14.27	0.68	
	>55-60	5,475	20	14.40	0.68	
	>60-65	6,068	21	14.40	0.68	
	>65-70	6,661	23	14.99	0.70	
	>70-75	7,034	25	15.13	0.70	
	>75-80	7,594	26	15.32	0.71	
	>80-85	8,153	28	15.17	0.71	**(C)**
Post-Top, American Revolution						
LED	>30-35	3,395	11	6.17	0.45	**(C)**
	>45-50	4,409	16	6.49	0.46	
Flood LED	>80-85	10,530	28	6.19	0.45	
	>120-130	16,932	43	6.69	0.47	
	>180-190	23,797	63	7.69	0.50	
	>370-380	48,020	127	11.86	0.61	**(C)**

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 Energy conservation, new market transformation, new renewable energy 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 3% 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. **(C)** **(C)**

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	(R)
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	(R)

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

Schedule		Adjustment Rate		
89				
	Secondary	0.000	¢ per kWh	(R)
	Primary	0.000	¢ per kWh	
	Subtransmission	0.000	¢ per kWh	
90		0.000	¢ per kWh	
91		0.000	¢ per kWh	
92		0.000	¢ per kWh	
95		0.000	¢ per kWh	(R)

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 deferred and 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.

DEFERRAL MECHANISM

For each calendar year that the Company anticipates that a new renewable resource or energy storage project associated with renewable energy resources will commence operation, the Company may file a deferral request the earlier of the resource online date or April 1. The deferral amount will be for the fixed revenue requirements of the resource less net dispatch benefits. For purposes of determining dispatch benefits, the forward curves used to set rates for the year under the Annual Power Cost Update will be used. The deferral will be amortized over the next calendar year in Schedule 122 unless otherwise approved by the Oregon Public Utility Commission (OPUC). 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 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	9.265	$72.10	$49.75	**(I)**
32/532	8.087	$112.23		**(I)** **(C)**
38/538	10.044	$699.35		
47	14.876	$89.68		
49/549	11.855	$431.93		**(C)**
83/583	2.951	$581.37		**(R)**

*Applicable beginning in 2019. The Fixed Charge Energy Rate for Schedule 83 includes fixed generation charges only. **(C)**

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA)

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532; 83 (starting in 2019), and 38, 47, 49, 538, 549 **(C)** and 583 (starting in 2022) 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. **(M)**

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA) (Continued)

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. (M)

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 Schedule 122 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 5.074 cents per kWh. (R)

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	0.216 ¢ per kWh	(I)
15	0.010 ¢ per kWh	
32	0.255 ¢ per kWh	(I)
38	0.010 ¢ per kWh	
47	0.010 ¢ per kWh	
49	0.010 ¢ per kWh	

(M)

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued)

Schedule	Adjustment Rate		
75			(M)
Secondary	0.010		
Primary	0.010		
Subtransmission	0.010		
83	0.204		(M)(I)
85			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
89			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
Subtransmission	0.010	¢ per kWh	
90	0.010	¢ per kWh	
91	0.010	¢ per kWh	
92	0.010	¢ per kWh	
95	0.010	¢ per kWh	
485			
Secondary	0.002	¢ per kWh	
Primary	0.002	¢ per kWh	
489			
Secondary	0.002	¢ per kWh	
Primary	0.002	¢ per kWh	
Subtransmission	0.002	¢ per kWh	
490	0.002	¢ per kWh	
491	0.002	¢ per kWh	
492	0.002	¢ per kWh	
495	0.002	¢ per kWh	
515	0.010	¢ per kWh	
532	0.255	¢ per kWh	(I)
538	0.010	¢ per kWh	
549	0.010	¢ per kWh	

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued)

Schedule	Adjustment Rate	
575		
Secondary	0.010 ¢ per kWh	
Primary	0.010 ¢ per kWh	
Subtransmission	0.010 ¢ per kWh	
583	0.204 ¢ per kWh	(I)
585		
Secondary	0.010 ¢ per kWh	
Primary	0.010 ¢ per kWh	
589		
Secondary	0.010 ¢ per kWh	
Primary	0.010 ¢ per kWh	
Subtransmission	0.010 ¢ per kWh	
590	0.010 ¢ per kWh	
591	0.010 ¢ per kWh	
592	0.010 ¢ per kWh	
595	0.010 ¢ per kWh	
689		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ 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:

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.

SCHEDULE 123 (Concluded)

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. If the amount of the proposed rate revision exceeds the 2% limit, only a 2% rate increase will be proposed and any remaining amount in the SNA balancing Account will be carried over to the following year(s). Rate revisions resulting in a rate decrease are not subject to the 2% limit. **(C)** **(C)**

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 December 31, 2025 if not extended by the Commission. **(C)**

SCHEDULE 125 (Continued)

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 1.0331. **(I)**

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 6, 2020, for one-time only and due to extraordinary wildfire events in the state of Oregon, the Company will file updated estimates with final planned maintenance outages for the following hydro facilities: Faraday, Oak Grove, Harriet Lake, Timothy Lake, and Stone Creek.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) 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, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

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.

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES

Schedule		¢ per kWh	
7		0.000	(R)
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		0.000	
91		0.000	
92		0.000	
95		0.000	(R)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

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.

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, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance 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.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record Annual 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.

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0331 to account for franchise fees, uncollectibles, and OPUC fees. **(I)**

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount 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.

Schedule 126 (Continued)

DEFINITIONS (Continued)

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.
- 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 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.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0331 to account for franchise fees, uncollectables, and OPUC fees. **(I)**

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

SCHEDULE 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 2021, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2022: **(C)** **(C)**

Schedule		Annual ¢ per kWh [1]	
32		2.154	**(R)**
38		1.682	
75	Secondary	1.793 [2]	
	Primary	1.773 [2]	
	Subtransmission	1.808 [2]	
83		2.092	
85	Secondary	1.905	
	Primary	1.867	**(R)**

(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 ¢ per kWh [1]	
89	Secondary	1.793	(R)
	Primary	1.773	
	Subtransmission	1.808	
90		1.446	
91		1.630	
95		1.630	
515		1.561	
532		2.154	
538		1.682	
549		2.772	
575	Secondary	1.793 [2]	
	Primary	1.773 [2]	
	Subtransmission	1.808 [2]	
583		2.092	
585	Secondary	1.905	
	Primary	1.867	
589	Secondary	1.793	
	Primary	1.773	
	Subtransmission	1.808	
590		1.446	
591		1.630	
592		1.618	
595		1.630	(R)

(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 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 - O: 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 P (2017), 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	
2018	3.339	3.294	3.007	2.953	2.892	2.732	2.805	
2019	3.072	3.031	2.760	2.711	2.653	2.513	2.546	
2020	3.072	3.031	2.760	2.711	2.653	2.513	2.546	
2021	3.072	3.031	2.760	2.711	2.653	2.513	2.546	
2022	2.245	2.240	2.029	2.014	1.973	1.826	1.903	(R)
After 2022	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

For Enrollment Period 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	2.145	2.167	1.894	1.879	1.813	1.853	1.838	**(R)**
2023	2.145	2.167	1.894	1.879	1.813	1.853	1.838	**(R)**
After 2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

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	1.549	1.568	1.311	1.307	1.238	1.273	1.295	**(R)**
2023	1.549	1.568	1.311	1.307	1.238	1.273	1.295	|
2024	1.549	1.568	1.311	1.307	1.238	1.273	1.295	**(R)**
After 2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

For Enrollment Period 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	2.340	2.346	2.070	2.052	2.090	2.017	1.993	(R)
2023	2.340	2.346	2.070	2.052	2.090	2.017	1.993	
2024	2.340	2.346	2.070	2.052	2.090	2.017	1.993	
2025	2.340	2.346	2.070	2.052	2.090	2.017	1.993	(R)
After 2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

For Enrollment Period T (2021), the current Transition Cost Adjustments are: (N)

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	2.123	2.091	1.752	1.720	1.683	1.687	1.742	
2023	2.123	2.091	1.752	1.720	1.683	1.687	1.742	
2024	2.123	2.091	1.752	1.720	1.683	1.687	1.742	
2025	2.123	2.091	1.752	1.720	1.683	1.687	1.742	
2026	2.123	2.091	1.752	1.720	1.683	1.687	1.742	
After 2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(N)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out

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

For Enrollment Period T (2021), the Transition Cost Adjustment will be: **(N)**

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	2.022	1.951	1.632	1.602	1.664	1.380	1.664
2023	2.022	1.951	1.632	1.602	1.664	1.380	1.664
2024	2.022	1.951	1.632	1.602	1.664	1.380	1.664

(N)

SCHEDULE 129 (Concluded)

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. This balancing account will be considered an "Automatic Adjustment Clause" as defined in ORS 757.210. 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	2.813	(R)
	Primary	2.784	
89	Secondary	2.666	
	Primary	2.637	
	Subtransmission	2.609	
90		2.631	
91		2.510	
92		2.510	
95		2.510	(R)

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 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	0.125	¢ per kWh	(I)
15/515	0.095	¢ per kWh	
32/532	0.114	¢ per kWh	
38/538	0.105	¢ per kWh	
47	0.138	¢ per kWh	
49/549	0.138	¢ per kWh	
75/575			
Secondary	0.102	¢ per kWh[1]	
Primary	0.101	¢ per kWh[1]	
Subtransmission	0.101	¢ per kWh[1]	
83/583	0.113	¢ per kWh	
85/585			
Secondary	0.110	¢ per kWh	
Primary	0.108	¢ per kWh	(I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 135 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
89/589			
Secondary	0.102	¢ per kWh	(I)
Primary	0.101	¢ per kWh	
Subtransmission	0.101	¢ per kWh	
90/590	0.096	¢ per kWh	
91/591	0.095	¢ per kWh	
92/592	0.099	¢ per kWh	
95/595	0.095	¢ per kWh	(I)

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.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the implementation and administration of demand response pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of demand response pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

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 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. **(C)**

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate		
7	0.016	¢ per kWh	(R)
15	0.027	¢ per kWh	
32	0.015	¢ per kWh	
38	0.016	¢ per kWh	
47	0.024	¢ per kWh	
49	0.018	¢ per kWh	
75			
Secondary	0.008	¢ per kWh[(1)]	
Primary	0.008	¢ per kWh[(1)]	
Subtransmission	0.010	¢ per kWh[(1)]	
83	0.012	¢ per kWh	
85			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	(R)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 137 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
89			
Secondary	0.008	¢ per kWh	(R)
Primary	0.008	¢ per kWh	
Subtransmission	0.010	¢ per kWh	
90	0.008	¢ per kWh	
91	0.027	¢ per kWh	
92	0.011	¢ per kWh	
95	0.027	¢ per kWh	(R)
485		¢ per kWh	(N)
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
489		¢ per kWh	
Secondary	0.008	¢ per kWh	
Primary	0.008	¢ per kWh	
Subtransmission	0.009	¢ per kWh	
490	0.008	¢ per kWh	
491	0.027	¢ per kWh	
492	0.011	¢ per kWh	
495	0.027	¢ per kWh	(N)
515	0.027	¢ per kWh	(R)
532	0.015	¢ per kWh	
538	0.016	¢ per kWh	
549	0.018	¢ per kWh	
575			
Secondary	0.008	¢ per kWh	
Primary	0.008	¢ per kWh	
Subtransmission	0.010	¢ per kWh	(R)

(M)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 137 (Concluded)

ADJUSTMENT RATES (Continued)

583	0.012	¢ per kWh	(R)
585			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
589			
Secondary	0.008	¢ per kWh	
Primary	0.008	¢ per kWh	
Subtransmission	0.010	¢ per kWh	
590	0.008	¢ per kWh	
591	0.027	¢ per kWh	
592	0.011	¢ per kWh	
595	0.027	¢ per kWh	(R)
689		¢ per kWh	(N)
Secondary	0.008	¢ per kWh	
Primary	0.008	¢ per kWh	
Subtransmission	0.009	¢ per kWh	(N)

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.

DEFERRAL MECHANISM

Each year the Company may file a deferral request. The deferral will be amortized over one year in this schedule unless otherwise directed by the Oregon Public Utility Commission.

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. (C)
(C)

SCHEDULE 138
ENERGY STORAGE COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with 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, and 576R.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.004	¢ per kWh
15/515	0.003	¢ per kWh
32/532	0.004	¢ per kWh
38/538	0.004	¢ per kWh
47	0.007	¢ per kWh
49/549	0.006	¢ per kWh
75/575		
Secondary	0.003	¢ per kWh
Primary	0.003	¢ per kWh
Subtransmission	0.003	¢ per kWh
83/583	0.004	¢ per kWh
85/585		
Secondary	0.004	¢ per kWh
Primary	0.004	¢ per kWh

SCHEDULE 138 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
89/589		
Secondary	0.003	¢ per kWh
Primary	0.003	¢ per kWh
Subtransmission	0.003	¢ per kWh
90/590	0.003	¢ per kWh
91/591	0.003	¢ per kWh
92/592	0.003	¢ per kWh
95/595	0.003	¢ 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.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the implementation and administration of the energy storage pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of energy storage pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

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	0.533	0.527	0.522	(R)
2023	0.533	0.527	0.522	
2024	0.533	0.527	0.522	
2025*	0.533	0.527	0.522	(R)
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	0.533	0.527	0.522	(R)
2023	0.533	0.527	0.522	
2024	0.533	0.527	0.522	
2025	0.533	0.527	0.522	
2026*	0.533	0.527	0.522	(R)
After 2027	0.000	0.000	0.000	

*Applicable pricing only to completion of five-year period and zero thereafter.

SCHEDULE 139 (Continued) **(T)**

TRANSITION COST ADJUSTMENT (Continued) **(N)**
Minimum Five Year Opt-Out

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	0.533	0.527	0.522
2023	0.533	0.527	0.522
2024	0.533	0.527	0.522
2025	0.533	0.527	0.522
2026	0.533	0.527	0.522
2027*	0.533	0.527	0.522
After 2028	0.000	0.000	0.000

*Applicable pricing only to completion of five-year period and zero thereafter. **(N)**

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.

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. This balancing account will be considered an "Automatic Adjustment Clause" as defined in ORS 757.210. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased participating load will be determined.

(M)

SCHEDULE 139 (Concluded)

TERM **(M)**

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. **(M)**

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. **(C)** **(C)**

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	0.334	¢ per kWh	**(I)**
15/515	0.238	¢ per kWh	
32/532	0.286	¢ per kWh	
38/538	0.265	¢ per kWh	
47	0.319	¢ per kWh	
49/549	0.328	¢ per kWh	
75/575			
Secondary	0.265	¢ per kWh	
Primary	0.262	¢ per kWh	
Subtransmission	0.264	¢ per kWh	
83/583	0.284	¢ per kWh	
85/585			
Secondary	0.274	¢ per kWh	
Primary	0.269	¢ per kWh	
89/589			
Secondary	0.265	¢ per kWh	
Primary	0.262	¢ per kWh	
Subtransmission	0.264	¢ per kWh	**(I)**

SCHEDULE 146 (Continued) (T)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
90/590	0.245	¢ per kWh
91/591	0.242	¢ per kWh
92/592	0.256	¢ per kWh
95/595	0.242	¢ per kWh

(I)
(I)

PART A- DECOMMISSIONING AMOUNTS (N)(M)

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. (N)

(M)
(D)

SCHEDULE 146 (Concluded)

DETERMINATION OF ADJUSTMENT AMOUNTS (M)

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 decommissioning revenue requirement and depreciation revenue requirement (Parts A and B). Any additional updates (Part C) to this schedule can only be made pursuant to 1) the removal of Colstrip from regulated service, or 2) rate change requests effectuated through a separate docketed proceeding as allowable through Oregon Revised Statutes and Oregon Administrative Rules (e.g., through a general rate case). (C) (C)(M)

BALANCING ACCOUNT (N)

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.

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.

(N)

SCHEDULE 150
TRANSPORTATION ELECTRIFICATION COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with transportation electrification 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, and 576R.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.016	¢ per kWh
15/515	0.027	¢ per kWh
32/532	0.015	¢ per kWh
38/538	0.017	¢ per kWh
47	0.024	¢ per kWh
49/549	0.018	¢ per kWh
75/575		
Secondary	0.010	¢ per kWh
Primary	0.008	¢ per kWh
Subtransmission	0.010	¢ per kWh
83/583	0.012	¢ per kWh
85/585		
Secondary	0.010	¢ per kWh
Primary	0.010	¢ per kWh
89/589		
Secondary	0.010	¢ per kWh
Primary	0.008	¢ per kWh
Subtransmission	0.010	¢ per kWh

SCHEDULE 150 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule		Adjustment Rate	
90/590		0.008	¢ per kWh
91/591		0.027	¢ per kWh
92/592		0.011	¢ per kWh
95/595		0.027	¢ per kWh
485			
	Secondary	0.010	¢ per kWh
	Primary	0.010	¢ per kWh
489			
	Secondary	0.009	¢ per kWh
	Primary	0.010	¢ per kWh
	Subtransmission	0.009	¢ per kWh
689			
	Secondary	0.009	¢ per kWh
	Primary	0.008	¢ per kWh
	Subtransmission	0.009	¢ per kWh

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.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the implementation and administration of transportation electrification pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of transportation electrification pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

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 300 (Continued)

LINE EXTENSIONS (Rule I)

Line Extension Allowance (Section 1)(1)

Residential Service All Electric(2)	$2,660.00 / dwelling unit	**(I)**
Residential Service Primary Other(3)	$1,867.00 / dwelling unit	
Schedule 32	$0.2638 / estimated annual kWh	
Schedules 38 and 83	$0.1082 / estimated annual kWh	
Schedules 85 and 89 Secondary Voltage Service	$0.0791 / estimated annual kWh	
Schedules 85 and 89 Primary Voltage Service	$0.0474 / estimated annual kWh	
Schedules 15, 91 and 95 Outdoor Lighting	$0.1992 / estimated annual kWh	**(I)**
Schedule 92 Traffic Signals	$0.0521 / estimated annual kWh	**(R)**
Schedules 47 and 49	$0.0995 / estimated annual kWh	**(I)**

Trenching or Boring (Section 2)

Trenching and backfilling associated with Service Installation except where General Rules and Regulations require actual cost.

In Residential Subdivisions:	
Short-side service connection up to 30 feet	$ 100.00
Otherwise:	
First 75 feet or less	$ 219.00
Greater than 75 feet	$ 3.80 / foot
Mainline trenching, boring and backfilling	Estimated Actual Cost

Lighting Underground Service Areas(4)

Installation of conduit on a wood pole for lighting purposes	$ 75.00 per pole

(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.

(4) Applies only to 1-inch conduit without brackets.

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	$ 100.00	
Service Locate Charge	$ 30.00	
Long-Side Service Connection	$ 120.00	

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$1077.00	(I)
Permanent Customer obtained		
Overhead Service	$607.00	
Underground Service	$632.00	
Existing service	$819.00	(I)

Enhanced Temporary Service

Fixed fee for initial 6-month period	$865.00	(C)
Fixed fee per 6-month renewal	$354.00	(C)

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, removal and energy for pole and luminaire. Energy will be calculated based on burning hours used for Option C Schedule 91, 95
(2) Charges may be assessed for training courses registered through the states of Oregon and Washington for electrical licensees.
(3) Based on the cost associated with instructor, facility, food, and materials per attendee.

SCHEDULE 485
LARGE NONRESIDENTIAL
COST OF SERVICE OPT-OUT
(201 - 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per SP*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$810.00	$760.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.48	$3.45	(I)
Over 200 kW	$2.28	$2.25	(I)
per kW of monthly On-Peak Demand	$1.60	$1.58	(R)
System Usage Charge			
per kWh	0.180 ¢	0.180 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 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 $1.850 per kW of monthly Demand. **(I)**

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	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

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 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	$5,380.00	$3,630.00	$5,680.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	(R)
Over 4,000 kW	$1.04	$1.03	$1.03	
per kW of monthly On-Peak Demand	$1.60	$1.58	$0.50	(R)
System Usage Charge				
per kWh	0.126 ¢	0.127 ¢	0.126 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 489 (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 $1.850 per kW of monthly Demand. **(I)**

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	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

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 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.

* 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) **(C)**

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. **(C)**

MONTHLY RATE

The Monthly Rate will be the sum of the following charges per SP*:

Basic Charge	$20,900.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.70	**(I)**
Over 4,000 kW	$1.39	**(I)**
per kW of monthly On-Peak Demand	$1.58	**(R)**
System Usage Charge		
per kWh	(0.023) ¢	**(I)**

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 490 (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 $1.850 per kW of monthly Demand. **(I)**

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	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

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 491 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company’s discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 7.051 ¢ per kWh **(I)**

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer’s Service Points (SPs) under this schedule.

SCHEDULE 491 (Continued)

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 $1.850 per kW of monthly Demand. **(I)**

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	**(R)**

SCHEDULE 491 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime [(1)]
	$124.00 per hour	$155.00 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 **							
	70	6,300	30	*	$2.93	$2.12	(R)(I)
	100	9,500	43	*	3.96	3.03	(R)(I)
	150	16,000	62	*	5.18	4.37	(I)
	200	22,000	79	*	6.54	5.57	(I)
	250	29,000	102	*	8.00	7.19	(I)
	400	50,000	163	*	12.48	11.49	(I)
Cobrahead, Non-Power Door	70	6.300	30	$6.83	3.22	2.12	(I)(R)
	100	9,500	43	7.44	4.08	3.03	(R)(I)
	150	16,000	62	8.84	5.43	4.37	(R)(I)
	200	22,000	79	10.68	6.70	5.57	(R)(I)
	250	29,000	102	11.91	8.26	7.19	(R)(I)
	400	50,000	163	16.40	12.59	11.49	(I)
Flood	250	29,000	102	13.22	8.46	7.19	(I)
	400	50,000	163	17.52	12.76	11.49	(I)
Early American Post-Top	100	9,500	43	8.33	4.23	3.03	(I)(R)
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	7.09	3.27	2.12	(R)(I)
	100	9,500	43	*	4.25	3.03	(C)(R)(I)
	150	16,000	62	*	5.65	4.37	(C)(R)(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 491 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black, Bronze, or Gray	20	$4.61	$0.17	**(R)(I)**
Fiberglass, Black or Bronze	30	7.49	0.28	**(I)**
Fiberglass, Gray	30	7.49	0.28	**(R)(I)**
Fiberglass, Smooth, Black or Bronze	18	4.89	0.19	**(R)(I)**
Fiberglass, Regular				
Black, Bronze, or Gray	18	$4.28	$0.16	**(I)**
	35	7.31	0.28	**(R)(I)**
Aluminum, Regular with Breakaway Base	35	18.74	0.71	**(I)**
Wood, Standard	30 to 35	$5.58	$0.21	**(I)**
Wood, Standard	40 to 55	6.57	0.25	**(I)**

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Acorn-Types							
HPS	100	9,500	43	$11.49	$4.70	$3.03	**(I)**
HADCO Victorian, HPS	150	16,000	62	12.83	6.04	4.37	**(I)**
	200	22,000	79	14.35	7.29	5.57	**(I)**
	250	29,000	102	15.88	8.89	7.19	**(I)**
HADCO Capitol Acorn, HPS	100	9,500	43	15.20	5.26	3.03	**(I)**
	150	16,000	62	*	6.56	4.37	**(C)(I)**
	200	22,000	79	*	7.84	5.57	**(C)(I)**
	250	29,000	102	*	8.08	7.19	**(C)(R)(I)**
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	12.59	4.84	3.03	**(I)**
	150	16,000	62	*	5.90	4.37	**(C)(I)**
HADCO Techtra, HPS	100	9,500	43	19.28	5.87	3.03	**(R)(I)**
	150	16,000	62	21.38	7.33	4.37	**(I)**
	250	29,000	102	*	9.92	7.19	**(C)(I)**
HADCO Westbrooke, HPS	70	6,300	30	13.65	4.23	*	**(I)**
	100	9,500	43	14.70	5.16	3.03	**(I)**

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	*	$6.79	$4.37	**(C)(I)**
	200	22,000	79	*	6.52	5.57	**(C)(R)(I)**
	250	29,000	102	$17.39	9.10	7.19	**(R)(I)**
Special Types							
Flood, Metal Halide	350	30,000	139	*	11.25	9.80	**(C)(I)**
Flood, HPS	750	105,000	285	28.58	21.88	20.10	**(I)**
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	4.51	**(I)**
Ornamental Acorn	55	2,800	21	*	*	1.48	**(I)**
Ornamental Acorn Twin	55	5,600	42	*	*	2.95	**(I)**
Composite, Twin	140	6,815	54	*	*	3.81	**(I)**
	175	9,815	66	*	*	4.65	**(I)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B		
Aluminum, Regular	25	$7.92	$0.30	**(R)**	
	30	9.09	0.34	**(R)**	
	35	10.52	0.40	**(R)**	
Aluminum Davit	25	8.45	0.32	**(R)**	
	30	9.52	0.36	**(R)**	
	35	10.88	0.41	**(R)**	**(I)**
	40	13.97	0.53	**(R)**	**(I)**
Aluminum Double Davit	30	10.56	0.40	**(R)**	**(I)** **(M)**

* 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, Fluted Ornamental	14	7.51	0.28	**(M)(R)**
Aluminum, Smooth Techtra Ornamental	18	16.41	0.62	**(R)**
Aluminum, Fluted Ornamental	16	7.79	0.30	**(R)**
Aluminum, Double-Arm, Smooth Ornamental	18	12.65	0.48	**(R)(I)**
Aluminum, Fluted Westbrooke	18	15.42	0.58	**(R)**
Aluminum, Non-Fluted Ornamental, Pendant	22	15.32	0.58	**(C)**
Fiberglass, Fluted Ornamental Black	14	10.51	0.40	**(R)(I)**
Fiberglass, Anchor Base, Gray or Black	35	9.98	0.38	**(R)**
Fiberglass, Anchor Base (Color may vary)	25	8.87	0.34	**(R)(I)**
	30	10.84	0.41	**(I)**

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Metal Halide	150	10,000	60	*	$5.39	$4.23	**(C)(R)(I)**
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.75	**(I)**
	175	7,000	66	9.07	5.71	4.65	**(I)**
	250	10,000	94	*	*	6.63	**(I)**
	400	21,000	147	15.44	11.46	10.36	**(I)**
	1,000	55,000	374	31.40	27.59	26.37	**(I)**
Holophane Mongoose,	150	16,000	62	*	6.35	4.37	**(C)(I)**
HPS	250	29,000	102	*	9.18	*	**(C)(I)**

* Not offered.

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$7.48	*	*	**(R)**
Mercury Vapor	175	7,000	66	10.01	$5.81	$4.65	**(I)**
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	4.23	**(I)**
	70	6,300	30	*	*	2.12	**(I)**
	100	9,500	43	*	4.52	3.03	**(R)(I)**
	150	16,000	62	*	5.26	4.37	**(R)(I)**
	250	29,000	102	*	*	7.19	**(I)**
	400	50,000	163	*	*	11.49	**(I)**
Metal Halide	250	20,500	99	*	7.88	6.98	**(I)**
	400	40,000	156	*	11.90	*	**(I)**
Cobrahead, Metal Halide	175	12,000	71	*	6.18	5.01	**(I)**
Flood, Metal Halide	400	40,000	156	16.34	12.20	11.00	**(I)**
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.92	*	**(R)**
100/150 Watt Ballast	100	9,500	43	*	3.92	*	**(R)**
100/150 Watt Ballast	150	16,000	62	*	5.26	4.37	**(R)(I)**
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.26	4.37	**(R)(I)**
KIM Archetype, HPS	250	29,000	102	*	9.20	7.19	**(I)**
	400	50,000	163	*	13.94	11.49	**(I)**

* Not offered

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$10.48	$3.69	*	(I)(R)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	$2.12	(I)
Mercury Vapor	175	7,000	66	*	*	4.65	(I)
Early American Post-Top, HPS							
Black	70	6,300	30	7.26	3.16	2.12	(I)(R)
Rectangle Type	200	22,000	79	*	*	5.57	(I)
Incandescent	92	1,000	31	*	*	2.19	(I)
	182	2,500	62	*	*	4.37	(I)
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	9.85	5.75	4.65	(I)
Flood, HPS	70	6,300	30	6.57	3.21	*	(R)
	100	9,500	43	7.49	4.10	3.03	(I)(R)
	200	22,000	79	11.49	6.73	5.57	(I)
Cobrahead, HPS							
Power Door	310	37,000	124	*	10.01	8.74	(C)(I)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	3.03	(I)
Twin ornamental, HPS	Twin 100	9,500	86	*	*	6.06	(I)
Compact Fluorescent	28	N/A	12	*	*	0.85	(I)

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B	
Aluminum Post	30	4.26	*	**(R)**
Aluminum, Painted Ornamental	35	*	*	**(C)**
Aluminum, Regular	16	4.26	0.16	**(R)**
Bronze Alloy GardCo	12	*	0.23	**(I)**
Concrete, Ornamental	35 or less	7.92	0.30	**(R)**
Fiberglass, Direct Bury with Shroud	18	6.30	0.24	**(R)**
Steel, Painted Regular **	25	7.92	0.30	**(R)**
Steel, Painted Regular **	30	9.09	0.34	**(R)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.41	**(I)**
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41	**(I)**
Wood, Laminated without Mast Arm	20	4.61	0.17	**(R)(I)**
Wood, Laminated Street Light Only	20	4.61	*	**(R)**
Wood, Curved Laminated	30	6.40	0.28	**(R)(I)**
Wood, Painted Underground	35	5.58	0.21	**(I)**

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$2.59	$2.26	**(R)(I)**
	165	12,000	60	*	2.03	1.06	**(R)**
	165	12,000	60	*	5.51	4.23	**(C)(I)**

SCHEDULE 492
TRAFFIC SIGNALS
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 500 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Service Point (SP)* is:

Distribution Charge 1.743 ¢ per kWh **(R)**

* 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 $1.850 per kW of monthly Demand. **(I)**

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	**(R)**

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 495 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/491/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A and Option B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 7.051 ¢ per kWh **(I)**

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's Service Points (SPs) under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

SCHEDULE 495 (Continued)

MARKET BASED PRICING OPTION (Continued)

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

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	**(R)**

SCHEDULE 495 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [(1)]	Straight Time	Overtime
	$124.00 per hour	$155.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Roadway LED	>20-25	3,000	8	$10.13	$0.97	(C)
	>25-30	3,470	9	5.12	1.04	
	>30-35	2,530	11	5.53	1.19	
	>35-40	4,245	13	5.42	1.33	
	>40-45	5,020	15	5.68	1.47	
	>45-50	3,162	16	5.85	1.54	
	>50-55	3,757	18	6.23	1.69	
	>55-60	4,845	20	6.04	1.82	
	>60-65	4,700	21	6.12	1.89	
	>65-70	5,050	23	4.49	2.04	
	>70-75	7,640	25	6.99	2.19	
	>75-80	8,935	26	7.07	2.26	
	>80-85	9,582	28	7.22	2.40	
	>85-90	10,230	30	7.33	2.55	
	>90-95	9,928	32	7.51	2.69	
	>95-100	11,719	33	7.58	2.76	
	>100-110	7,444	36	8.07	2.97	
	>110-120	12,340	39	8.01	3.18	
	>120-130	13,270	43	8.30	3.46	
	>130-140	14,200	46	9.33	3.69	
	>140-150	15,250	50	10.59	4.01	
	>150-160	16,300	53	10.73	4.22	
	>160-170	17,300	56	11.01	4.43	
	>170-180	18,300	60	11.11	4.70	
	>180-190	19,850	63	11.51	4.92	
	>190-200	21,400	67	11.90	5.20	(C)

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Acorn						
LED	>35-40	3,262	13	$12.62	$1.53	(C)
	>40-45	3,500	15	12.85	1.67	
	>45-50	5,488	16	10.84	1.68	
	>50-55	4,000	18	13.07	1.88	
	>55-60	4,213	20	13.11	2.02	
	>60-65	4,273	21	13.29	2.09	
	>65-70	4,332	23	13.29	2.23	
	>70-75	4,897	25	13.46	2.37	
HADCO LED	70	5,120	24	17.27	2.41	(C)
Pendant LED (Non-Flared)	36	3,369	12	13.93	1.50	(R)(I)
	53	5,079	18	15.08	1.94	
	69	6,661	24	15.61	2.36	
	85	8,153	29	16.49	2.73	(R)(I)
						(D)
Pendant LED (Flared)	>35-40	3,369	13	14.16	1.57	(C)
	>40-45	3,797	15	14.41	1.71	
	>45-50	4,438	16	14.48	1.78	
	>50-55	5,079	18	15.54	1.95	
	>55-60	5,475	20	15.81	2.09	
	>60-65	6,068	21	15.88	2.16	
	>65-70	6,661	23	16.61	2.32	
	>70-75	7,034	25	16.89	2.46	
	>75-80	7,594	26	17.15	2.54	
	>80-85	8,153	28	17.14	2.68	(C)
Post-Top, American Revolution LED	>30-35	3,395	11	6.95	1.23	(C)
	>45-50	4,409	16	7.62	1.59	
Flood LED	>80-85	10,530	28	8.16	2.42	
	>120-130	16,932	43	9.72	3.50	
	>180-190	23,797	63	12.13	4.94	
	>370-380	48,020	127	20.81	9.56	(C)

(M)

SCHEDULE 495 (Continued)

SPECIALTY SERVICES OFFERED (M)

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. (M)

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.

(M)

SCHEDULE 495 (Continued)

SPECIAL CONDITIONS (Continued)

(M)

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. (M)

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 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. **(N)**

Distribution Charge 7.068 ¢ per kWh **(N)**

SERVICE RATES FOR AREA LIGHTING

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$9.00(2)	**(I)**
	400	21,000	147	15.18(2)	**(I)**
	1,000	55,000	374	31.17(2)	**(I)**
HPS	70	6,300	30	6.75(2)	**(I)**
	100	9,500	43	7.37	**(R)**
	150	16,000	62	8.77	**(R)**
	200	22,000	79	10.40	**(I)**
	250	29,000	102	11.64	**(I)**
	310	37,000	124	13.39(2)	**(I)**
	400	50,000	163	16.14	**(I)**
					(M)

(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	7.42[2]	(I) (M)
	200	22,000	79	11.21[2]	(I)
	250	29,000	102	12.95	(I)
	400	50,000	163	17.26	(I)
Shoebox, HPS (bronze color, flat lens,	70	6,300	30	7.01	(R)
or drop lens, multi-volt)	100	9,500	43	8.38	(R)
	150	16,500	62	10.11	(I) (M)
Special Acorn Type, HPS	100	9,500	43	$ 11.21	(I)
HADCO Victorian, HPS	150	16,500	62	12.55	(I)
	200	22,000	79	14.07	(I)
	250	29,000	102	15.61	(I)
Early American Post-Top, HPS, Black	100	9,500	43	8.26	(I)
Special Types					
Cobrahead, Metal Halide	150	10,000	60	8.99	(R)
Cobrahead, Metal Halide	175	12,000	71	10.02	(I)
Flood, Metal Halide	350	30,000	139	16.57	(I)
Flood, Metal Halide	400	40,000	156	16.08	(I)
Flood, HPS	750	105,000	285	28.33	(I)
HADCO Independence, HPS	100	9,500	43	12.31	(I)
Alternative Special Acorn - Techtra	165	12,000	60	22.94	(C)
HADCO Capitol Acorn, HPS	100	9,500	43	14.93	(I)
	200	22,000	79	17.71	(I) (D)
	250	29,000	102	10.66	(R)
HADCO Techtra, HPS	100	9,500	43	19.00	(R)
	150	16,000	62	21.10	(I)
					(D)
HADCO Westbrooke, HPS	70	6,300	30	13.36	(I)
	100	9,500	43	14.43	(I)
					(D)
	250	29,000	102	17.16	(R)
Holophane Mongoose, HPS	150	16,000	62	14.66	(I)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[(1)] Per Luminaire	
Acorn					
LED	>35-40	3,262	13	$7.75	(C)
	>40-45	3,500	15	6.21	
	>45-50	5,488	16	10.56	
	>50-55	4,000	18	6.43	
	>55-60	4,213	20	5.81	
	>60-65	4,273	21	8.38	
	>65-70	4,332	23	13.01	
	>70-75	4,897	25	6.30	
HADCO LED	70	5,120	24	15.19	(C)
Roadway LED	>25-30	3,470	9	13.35	(C)
	>30-35	2,530	11	3.44	
	>35-40	4,245	13	3.89	
	>40-45	5,020	15	6.90	
	>45-50	3,162	16	3.76	
	>50-55	3,757	18	4.14	
	>55-60	4,845	20	7.75	
	>60-65	4,700	21	8.79	
	>65-70	5,050	23	4.71	
	>70-75	7,640	25	13.16	
	>75-80	8,935	26	7.72	
	>80-85	9,582	28	6.21	
	>85-90	10,230	30	8.29	
	>90-95	9,928	32	6.63	
	>95-100	11,719	33	6.70	
	>100-110	7,444	36	5.98	
	>110-120	12,340	39	7.71	
	>120-130	13,270	43	7.99	
	>130-140	14,200	46	9.05	
	>140-150	15,250	50	8.54	
	>150-160	16,300	53	16.37	
	>160-170	17,300	56	8.97	
	>170-180	18,300	60	10.83	
	>180-190	19,850	63	9.47	
	>190-200	21,400	67	11.63	(C)

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Pendant LED (Non-Flare)	36	3,369	12	11.84	**(C)(M)**
	53	5,079	18	14.79	
	69	6,661	24	15.34	
	85	8,153	29	16.21	
Pendant LED (Flare)	>35-40	3,369	13	12.07	
	>40-45	3,797	15	8.01	
	>45-50	4,438	16	8.08	
	>50-55	5,079	18	15.25	
	>55-60	5,475	20	12.99	
	>60-65	6,068	21	13.06	
	>65-70	6,661	23	16.33	
	>70-75	7,034	25	13.38	
	>75-80	7,594	26	14.96	
	>80-85	8,153	28	16.86	**(C)(M)**
CREE XSP LED	>20-25	2,529	8	2.83	**(C)**
	>30-35	4,025	1411	13.60	
	>40-45	3,819	1615	3.32	
	>45-50	4,373	16	3.63	
	>55-60	5,863	1920	3.71	
	>65-70	9,175	3123	15.47	
	>90-95	8,747	32	4.89	
	130-140	18,700	46	17.14	
Post-Top, American Revolution LED	>30-35	3,395	11	4.86	
	>45-50	4,409	16	5.53	
Flood LED	>80-85	10,530	29	13.24	
	120-130	16,932	44	6.07	
	180-190	23,797	63	15.76	
	370-380	48,020	127	20.40	**(C)**

(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	$ 5.32	**(I) (M)**
	40 to 55	6.31	**(I)**
Wood, Painted Underground	35 or less	5.32 [3]	**(I)**
Wood, Curved laminated	30 or less	6.32 [3]	**(R)**
Aluminum, Regular	16	4.07	**(R)**
	25	7.59	**(R)**
	30	8.76	**(R)**
	35	10.19	**(R)**
Aluminum, Fluted Ornamental	14	7.31	**(R)**
Aluminum, Fluted Ornamental	16	7.59	**(R)**
			(D)
			(M)
Aluminum Davit	25	$ 8.12	**(R)**
	30	9.19	**(R)**
	35	10.55	**(R)**
	40	13.58	**(R)**
Aluminum Double Davit	30	10.23	**(R)**
Aluminum, Smooth Techtra Ornamental	18	16.08	**(R)**
Aluminum, Fluted Ornamental	18	15.09	**(C)**
Aluminum, Non-Fluted Ornamental, Pendant	22	14.99	**(C)**
Fiberglass Fluted Ornamental; Black	14	9.82	**(R)**
Fiberglass, Regular			
Black	20	4.41	**(R)**
Gray or Bronze	30	7.16	**(R)**
Black, Gray, or Bronze	35	7.05	**(R)**
Fiberglass, Anchor Base, Gray or Black	35	9.82	**(R)**
			(D)
Fiberglass, Direct Bury with Shroud	18	5.97	**(R)**

(2) No pole charge for luminaires placed on existing Company-owned distribution poles.
(3) No new service.

SCHEDULE 515 (Concluded)

INSTALLATION CHARGE **(M)**

See Schedule 300 regarding the installation of conduit on wood poles **(M)**

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	$20.00	
Three Phase	$29.00	
Distribution Charge		
First 5,000 kWh	5.265 ¢ per kWh	(I)
Over 5,000 kWh	1.186 ¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 538
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers who have chosen to receive service from an Electricity Service Supplier (ESS), and: 1) served at Secondary Demand Voltage whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW; or 2) who were receiving service on Schedule 38 as of December 31, 2015.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge	$30.00		
Distribution Charge	7.010	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 549
IRRIGATION AND DRAINAGE PUMPING
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS) for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

<u>Basic Charge</u>		
Summer Months**	$45.00	
Winter Months**	No Charge	
<u>Distribution Charge</u>		
First 50 kWh per kW of Demand	9.754 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	7.754 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who receive Electricity Service from an Electricity Service Supplier (ESS) and who supply all or some portion of their load by self generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$5,380.00	$3,630.00	$5,680.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	(R)
Over 4,000 kW	$1.04	$1.03	$1.03	|
per kW of monthly On-Peak Demand**	$1.60	$1.58	$0.50	(R)
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	0.252¢	0.250¢	0.248¢	(I)

* 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 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:*

	Secondary	Primary	Subtransmission	
Daily Economic Replacement Power (ERP) Demand Charge				
per kW of Daily ERP Demand during On-Peak hours per day**	$0.072	$0.072	$0.071	**(R)(I)**
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 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	$35.00	
Three Phase Service	$45.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$5.12	(I)
Over 30 kW	$5.02	(I)
per kW of monthly On-Peak Demand	$1.60	(R)
System Usage Charge		
per kWh	0.722 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 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	$810.00	$760.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.48	$3.45	(I)
Over 200 kW	$2.28	$2.25	(I)
per kW of monthly On-Peak Demand	$1.60	$1.58	(R)
System Usage Charge			
per kWh	0.180 ¢	0.180 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 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	$5,380.00	$3,630.00	$5,680.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	(R)
Over 4,000 kW	$1.04	$1.03	$1.03	
per kW of monthly on-peak Demand	$1.60	$1.58	$0.50	(R)
System Usage Charge				
per kWh	0.126 ¢	0.127 ¢	0.126 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 590
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW and Aggregate to >30 MWa) **(C)**

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. **(C)**

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	$20,900.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.70	**(I)**
Over 4,000 kW	$1.39	**(I)**
per kW of monthly on-peak Demand	$1.58	**(R)**
System Usage Charge		
per kWh	(0.023) ¢	**(I)**

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.051 ¢ per kWh	**(I)**
Energy Charge	Provided by Electricity Service Supplier	

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$124.00 per hour	$155.00 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 **							
	70	6,300	30	*	$2.93	$2.12	(R)(I)
	100	9,500	43	*	3.96	3.03	(R)(I)
	150	16,000	62	*	5.18	4.37	(I)
	200	22,000	79	*	6.54	5.57	(I)
	250	29,000	102	*	8.00	7.19	(I)
	400	50,000	163	*	12.48	11.49	(I)
Cobrahead, Non-Power Door	70	6.300	30	$6.83	3.22	2.12	(I)(R)
	100	9,500	43	7.44	4.08	3.03	(R)(I)
	150	16,000	62	8.84	5.43	4.37	(R)(I)
	200	22,000	79	10.68	6.70	5.57	(R)(I)
	250	29,000	102	11.91	8.26	7.19	(R)(I)
	400	50,000	163	16.40	12.59	11.49	(I)(R)
Flood	250	29,000	102	13.22	8.46	7.19	(I)
	400	50,000	163	17.52	12.76	11.49	(I)
Early American Post-Top	100	9,500	43	8.33	4.23	3.03	(I)(R)
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	7.09	3.27	2.12	(R)(I)
	100	9,500	43	*	4.25	3.03	(C)(R)(I)
	150	16,000	62	*	5.65	4.37	(C)(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 591 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black, Bronze, or Gray	20	$4.61	$0.17	(R)(I)
Fiberglass, Black or Bronze	30	7.49	0.28	(I)
Fiberglass, Gray	30	7.49	0.28	(R)(I)
Fiberglass, Smooth, Black or Bronze	18	4.89	0.19	(R)(I)
Fiberglass, Regular				
Black, Bronze, or Gray	18	$4.28	$0.16	(I)
	35	7.31	0.28	(R)(I)
Aluminum, Regular with Breakaway Base	35	18.74	0.71	(I)
Wood, Standard	30 to 35	$5.58	$0.21	(I)
Wood, Standard	40 to 55	6.57	0.25	(I)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Types							
HPS	100	9,500	43	$11.49	$4.70	$3.03	(I)
HADCO Victorian, HPS	150	16,000	62	12.83	6.04	4.37	(I)
	200	22,000	79	14.35	7.29	5.57	(I)
	250	29,000	102	15.88	8.89	7.19	(I)
HADCO Capitol Acorn, HPS	100	9,500	43	15.20	5.26	3.03	(I)
	150	16,000	62	*	6.56	4.37	(C)(I)
	200	22,000	79	*	7.84	5.57	(C)(I)
	250	29,000	102	*	8.08	7.19	(C)(R)(I)
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	12.59	4.84	3.03	(I)
	150	16,000	62	*	5.90	4.37	(C)(R)(I)
HADCO Techtra, HPS	100	9,500	43	19.28	5.87	3.03	(R)(I)
	150	16,000	62	21.38	7.33	4.37	(I)
	250	29,000	102	*	9.92	7.19	(C)(I)
HADCO Westbrooke, HPS	70	6,300	30	13.65	4.23	*	(I)
	100	9,500	43	14.70	5.16	3.03	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	*	$6.79	$4.37	**(C)(I)**
	200	22,000	79	*	6.52	5.57	**(C)(R)(I)**
	250	29,000	102	$17.39	9.10	7.19	**(R)(I)**
Special Types							
Flood, Metal Halide	350	30,000	139	*	11.25	9.80	**(C)(I)**
Flood, HPS	750	105,000	285	28.58	21.88	20.10	**(I)**
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	4.51	**(I)**
Ornamental Acorn	55	2,800	21	*	*	1.48	**(I)**
Ornamental Acorn Twin	55	5,600	42	*	*	2.95	**(I)**
Composite, Twin	140	6,815	54	*	*	3.81	**(I)**
	175	9,815	66	*	*	4.65	**(I)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$7.92	$0.30	**(R)**
	30	9.09	0.34	**(R)**
	35	10.52	0.40	**(R)**
Aluminum Davit	25	8.45	0.32	**(R)**
	30	9.52	0.36	**(R)**
	35	10.88	0.41	**(R)(I)**
	40	13.97	0.53	**(R)(I)**
Aluminum Double Davit	30	10.56	0.40	**(R)**
Aluminum, Fluted Ornamental	14	7.51	0.28	**(R)**

* 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	16.41	0.62	**(R)**
Aluminum, Fluted Ornamental	16	7.79	0.30	**(R)**
Aluminum, Double-Arm, Smooth Ornamental	18	12.65	0.48	**(R)(I)**
Aluminum, Fluted Westbrooke	18	15.42	0.58	**(R)**
Aluminum, Non-Fluted Ornamental, Pendant	22	15.32	0.58	**(C)**
Fiberglass, Fluted Ornamental Black	14	10.51	0.40	**(R)(I)**
Fiberglass, Anchor Base, Gray or Black	35	9.98	0.38	**(R)**
Fiberglass, Anchor Base (Color may vary)	25	8.87	0.34	**(R)(I)**
	30	10.84	0.41	**(I)**

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Metal Halide	150	10,000	60	*	$5.39	$4.23	**(C)(R)(I)**
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.75	**(I)**
	175	7,000	66	9.07	5.71	4.65	**(I)**
	250	10,000	94	*	*	6.63	**(I)**
	400	21,000	147	15.44	11.46	10.36	**(I)**
	1,000	55,000	374	31.40	27.59	26.37	**(I)**
Holophane Mongoose, HPS	150	16,000	62	*	6.35	4.37	**(C)(I)**
	250	29,000	102	*	9.18	*	**(C)(I)**

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$7.48	*	*	(R)
Mercury Vapor	175	7,000	66	10.01	$5.81	$4.65	(I)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	4.23	(I)
	70	6,300	30	*	*	2.12	(I)
	100	9,500	43	*	4.52	3.03	(R)(I)
	150	16,000	62	*	5.26	4.37	(R)(I)
	250	29,000	102	*	*	7.19	(I)
	400	50,000	163	*	*	11.49	(I)
Metal Halide	250	20,500	99	*	7.88	6.98	(I)
	400	40,000	156	*	11.90	*	(I)
Cobrahead, Metal Halide	175	12,000	71	*	6.18	5.01	(I)
Flood, Metal Halide	400	40,000	156	16.34	12.20	11.00	(I)
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.92	*	(R)
100/150 Watt Ballast	100	9,500	43	*	3.92	*	(R)
100/150 Watt Ballast	150	16,000	62	*	5.26	4.37	(R)(I)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.26	4.37	(R)(I)
KIM Archetype, HPS	250	29,000	102	*	9.20	7.19	(I)
	400	50,000	163	*	13.94	11.49	(I)

* Not offered

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$10.48	$3.69	*	**(I)**
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	$2.12	**(I)**
Mercury Vapor	175	7,000	66	*	*	4.65	**(I)**
Early American Post-Top, HPS							
Black	70	6,300	30	7.26	3.16	2.12	**(I)(R)**
Rectangle Type	200	22,000	79	*	*	5.57	**(I)**
Incandescent	92	1,000	31	*	*	2.19	**(I)**
	182	2,500	62	*	*	4.37	**(I)**
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	9.85	5.75	4.65	**(I)**
Flood, HPS	70	6,300	30	6.57	3.21	*	**(R)**
	100	9,500	43	7.49	4.10	3.03	**(I)(R)**
	200	22,000	79	11.49	6.73	5.57	**(I)**
Cobrahead, HPS							
Power Door	310	37,000	124	*	10.01	8.74	**(C)(I)(R)**
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	3.03	**(I)**
Twin ornamental, HPS	Twin 100	9,500	86	*	*	6.06	**(I)**
Compact Fluorescent	28	N/A	12	*	*	0.85	**(I)**

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B	
Aluminum Post	30	4.26	*	(R)
Aluminum, Painted Ornamental	35	*	*	(C)
Aluminum, Regular	16	4.26	0.16	(R)
Bronze Alloy GardCo	12	*	0.23	(I)
Concrete, Ornamental	35 or less	7.92	0.30	(R)
Fiberglass, Direct Bury with Shroud	18	6.30	0.24	(R)
Steel, Painted Regular **	25	7.92	0.30	(R)
Steel, Painted Regular **	30	9.09	0.34	(R)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.41	(I)
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41	(I)
Wood, Laminated without Mast Arm	20	4.61	0.17	(I)
Wood, Laminated Street Light Only	20	4.61	*	(I)
Wood, Curved Laminated	30	6.40	0.28	(R)(I)
Wood, Painted Underground	35	5.58	0.21	(I)

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$2.59	$2.26	(R)(I)
	165	12,000	60	*	2.03	1.06	(R)
	165	12,000	60	*	5.51	4.23	(C)(I)

SCHEDULE 595 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A and Option B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 7.051 ¢ per kWh **(I)**

Energy Charge Provided by Electricity Service Supplier

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$124.00 per hour	$155.00 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.

(M)

SCHEDULE 595 (Continued)

RATES FOR STANDARD LIGHTING (Continued) **(M)**
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	
Roadway LED	>20-25	3,000	8	$10.13	$0.97	**(C)**
	>25-30	3,470	9	5.12	1.04	
	>30-35	2,530	11	5.53	1.19	
	>35-40	4,245	13	5.42	1.33	
	>40-45	5,020	15	5.68	1.47	
	>45-50	3,162	16	5.85	1.54	
	>50-55	3,757	18	6.23	1.69	
	>55-60	4,845	20	6.04	1.82	
	>60-65	4,700	21	6.12	1.89	
	>65-70	5,050	23	6.78	2.04	
	>70-75	7,640	25	6.99	2.19	
	>75-80	8,935	26	7.07	2.26	
	>80-85	9,582	28	7.22	2.40	
	>85-90	10,230	30	7.33	2.55	
	>90-95	9,928	32	7.51	2.69	
	>95-100	11,719	33	7.58	2.76	
	100-110	7,444	36	8.07	2.97	
	110-120	12,340	39	8.01	3.18	
	120-130	13,270	43	8.30	3.46	
	130-140	14,200	46	9.33	3.69	
	140-150	15,250	50	10.59	4.01	
	150-160	16,300	53	10.73	4.22	
	160-170	17,300	56	11.01	4.43	
	170-180	18,300	60	11.11	4.70	
	180-190	19,850	63	11.51	4.92	
	190-200	21,400	67	11.90	5.20	**(C)**

(M)

SCHEDULE 595 (Continued)

RATES FOR STANDARD LIGHTING (Continued) (M)

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. (M)
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

SCHEDULE 595 (Continued)

RATES FOR STANDARD LIGHTING (Continued) (M)
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)

(M)

SCHEDULE 595 (Continued)

RATES FOR DECORATIVE LIGHTING

(M)

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	$12.62	$1.53	(C)
	>40-45	3,500	15	12.85	1.67	
	>45-50	5,488	16	10.84	1.68	
	>50-55	4,000	18	13.07	1.88	
	>55-60	4,213	20	13.11	2.02	
	>60-65	4,273	21	13.29	2.09	
	>65-70	4,332	23	13.29	2.23	
	>70-75	4,897	25	13.46	2.37	
HADCO LED	70	5,120	24	17.27	2.41	(C)
Pendant LED (Non-Flared)	36	3,369	12	13.93	1.50	(R)(I)
	53	5,079	18	15.08	1.94	
	69	6,661	24	15.61	2.36	
	85	8,153	29	16.49	2.73	(R)(I)
						(D)
Pendant LED (Flared)	>35-40	3,369	13	14.16	1.57	(C)
	>40-45	3,797	15	14.41	1.71	
	>45-50	4,438	16	14.48	1.78	
	>50-55	5,079	18	15.54	1.95	
	>55-60	5,475	20	15.81	2.09	
	>60-65	6,068	21	15.88	2.16	
	>65-70	6,661	23	16.61	2.32	
	>70-75	7,034	25	16.89	2.46	
	>75-80	7,594	26	17.15	2.54	(C)
	>80-85	8,153	28	17.14	2.68	
Post-Top, American Revolution						
LED	>30-35	3,395	11	6.95	1.23	(C)
	>45-50	4,409	16	7.62	1.59	
				8.16	2.42	
Flood LED	>80-85	10,530	28	9.72	3.50	
	>120-130	16,932	43	12.13	4.94	
	>180-190	23,797	63	20.81	9.56	
	>370-380	48,020	127	$12.62	$1.53	(C)

(M)

SCHEDULE 595 (Continued)

(M)

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, PortlandGeneral.com/business

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.

(M)

SCHEDULE 595 (Continued)

SPECIAL CONDITIONS (Continued) **(M)**

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. **(M)**

SCHEDULE 595 (Continued)

SPECIAL CONDITIONS (Continued) **(M)**

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. **(M)**

SCHEDULE 595 (Continued) **(T)**

SPECIAL CONDITIONS (Continued) **(M)**

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. **(M)**

SCHEDULE 595 (Concluded)

SPECIAL CONDITIONS (Continued) **(M)**

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.

(M)

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	(R)

ESS BILLING SERVICES

(1)	ESS Consolidated Bill Billing Credit	$ 0.63 per bill
(2)	Late Pay Charge	2.0 % 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 SYSTEM LOSSES

The ESS will schedule sufficient Energy to provide for the following losses on the Company's system:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Losses:	4.20%	3.09%	1.96%	**(C)**

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	$5,380.00	$3,630.00	$5,680.00	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	**(R)**
Over 4,000 kW	$1.04	$1.03	$1.03	
per kW of monthly On-Peak Demand	$1.60	$1.58	$0.50	**(R)**
System Usage Charge				
per kWh	0.126 ¢	0.127 ¢	0.126 ¢	**(I)**
Administrative Fee	$0.00	$0.00	$0.00	

* See Schedule 100 for applicable adjustments.

** The Customer's load, as reflected in the opt-out agreement executed between the Customer and PGE, may be higher than that reflected in a minimum load agreement for purposes of calculating the minimum monthly Facility Capacity and monthly Demand for the SP, for any Customer with dedicated substation capacity and/or redundant distribution facilities.

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 $1.850 per kW of monthly Demand. **(I)**

SCHEDULE 689 (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	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

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.

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.

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	0.326	¢ per kWh	Distribution Charge	**(I)**
15	0.589	¢ per kWh	Distribution Charge	**(I)**
32	0.296	¢ per kWh	Distribution Charge	**(I)**
38	0.303	¢ per kWh	Distribution Charge	**(R)**
47	0.486	¢ per kWh	Distribution Charge	**(R)**
49	0.362	¢ per kWh	Distribution Charge	**(R)**
75				
Secondary	0.148	¢ per kWh	System Usage Charge	**(R)**
Primary	0.146	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.145	¢ per kWh	System Usage Charge	**(R)**

DO NOT BILL

SCHEDULE 750 (Continued)

FRANCHISE FEE RATE RECOVERY (Continued)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate	Included in:	
83	0.222 ¢ per kWh	System Usage Charge	**(R)**
85			
Secondary	0.177 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.175 ¢ per kWh	System Usage Charge	**(R)**
89			
Secondary	0.148 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.146 ¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.145 ¢ per kWh	System Usage Charge	**(R)**
90	0.131 ¢ per kWh	System Usage Charge	**(R)**
91	0.561 ¢ per kWh	Distribution Charge	**(I)**
92	0.166 ¢ per kWh	Distribution Charge	**(R)**
95	0.561 ¢ per kWh	Distribution Charge	**(I)**
485			
Secondary	0.049 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.048 ¢ per kWh	System Usage Charge	**(R)**
489			
Secondary	0.022 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.022 ¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.022 ¢ per kWh	System Usage Charge	**(R)**
490	0.010 ¢ per kWh	System Usage Charge	**(R)**
491	0.442 ¢ per kWh	Distribution Charge	**(I)**
492	0.040 ¢ per kWh	Distribution Charge	**(R)**
495	0.442 ¢ per kWh	Distribution Charge	**(I)**

SCHEDULE 750 (Concluded)

FRANCHISE FEE RATE RECOVERY (Concluded)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate		Included in:	
515	0.471	¢ per kWh	Distribution Charge	**(I)**
532	0.153	¢ per kWh	Distribution Charge	**(I)**
538	0.171	¢ per kWh	Distribution Charge	**(R)**
549	0.199	¢ per kWh	Distribution Charge	**(I)**
575				
Secondary	0.022	¢ per kWh	System Usage Charge	**(R)**
Primary	0.022	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.022	¢ per kWh	System Usage Charge	**(R)**
583	0.079	¢ per kWh	System Usage Charge	**(I)**
585				
Secondary	0.049	¢ per kWh	System Usage Charge	**(R)**
Primary	0.048	¢ per kWh	System Usage Charge	**(R)**
589				
Secondary	0.022	¢ per kWh	System Usage Charge	**(R)**
Primary	0.022	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.022	¢ per kWh	System Usage Charge	**(R)**
590	0.010	¢ per kWh	System Usage Charge	**(R)**
591	0.442	¢ per kWh	Distribution Charge	**(I)**
592	0.040	¢ per kWh	Distribution Charge	**(R)**
595	0.442	¢ per kWh	Distribution Charge	**(I)**
689				
Secondary	0.022	¢ per kWh	System Usage Charge	**(R)**
Primary	0.022	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.022	¢ per kWh	System Usage Charge	**(R)**

29. 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.

30. Losses (N)

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.

31. Multi-Family Dwelling

A residential building that contains three or more dwelling units. (N)

32. Network Meter (T)

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.

33. Nonresidential Customer (T)

A Customer that does not meet the definition of a Residential Customer.

34. Non-Network Meter (Residential only) (T)

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.

35. Operational Order to Deliver Electricity (T)

An order issued by the Company to scheduling ESSs to deliver additional Electricity for purposes of maintaining the integrity of the Company's facilities.

36. Portfolio (T)

A set of product and pricing options provided to Residential Customers and Small Nonresidential Customers.

37. Premises (T)

Real and personal property owned and/or used by a Customer at a single location, which contains a Service Point.

38. Reactive Demand (T)

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.

39. Reactive Demand Charge (T)

A charge for Reactive Demand assessed to Customers with loads that are supplied Reactive Demand on the Company's system.

40. Residential Customer (T)

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.

41. **Scheduled Crew Hours** **(T)**

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.

42. **Service Point (SP)** **(T)**

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.

43. **Service Point Identification (SPID)** **(T)**

A code that identifies each unique Service Point and associated Company meter location (if applicable).

44. **Single-Family Dwelling** **(N)**

A residential building that contains less than three dwelling units. **(N)**

45. **Site** **(T)**

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;

(M)

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 **(M)** **(M)**

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.

46. **Small Nonresidential Customer** **(T)**

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.

47. **Standard Service** **(T)**

A service option provided by the Company to a Nonresidential Customer who elects to purchase Electricity from the Company rather than from an ESS.

48. **Summer Months** **(T)**

Summer Months are the six regular Billing Periods from May through October.

49. **Tariff** **(T)**

This Tariff, including all schedules, rules and regulations as they may be modified or amended from time to time.

50. **Theft of Service** **(T)**

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.

51. **Renewable Energy Certificates** **(T)**

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.

52. Transient Occupancy **(T)**

Tenancy at a Premise for a duration of less than 30 days.

53. Utility Provided Service **(T)**

The provision of Electricity Service to a Customer by the Company.

54. Winter Months

Winter Months are the six regular Billing Periods from November through April. **(T)**

RULE B (Concluded)

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 **(C)**
Customers that are critically essential to public safety and welfare. **(C)**

The Company maintains a list of critical Customers that includes but is not limited **(C)**
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. **(C)**

B. **Service Priority [Order]** **(C)**

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. **(C)**

The priorities for service restoration are generally as follows:

1) **Protect Public Safety**

The Company will clear energized, downed power lines and repair **(C)**
equipment that poses a public safety hazard. The Company will ensure that critical [Customers'] facilities have power. **(C)**

2) **Check Generation Facilities** (N)

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. (N)

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. (C)

4) **Repair Substations** (T)

The Company will repair substations making it possible to restore service to distribution lines. (C)

5) **Repair Feeder Distribution Lines** (C)

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. (C)

6) **Repair Tap Lines** (C)

The Company will repair tap lines that serve smaller groupings, such as Residential Customers. (C)

7) **Repair Individual Service Connections** (C)

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)

(M)

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. **(M)** **(M)**

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: **(M)** **(T)**

a) The Applicant will provide a cash payment of 10% of the estimated Line Extension Cost prior to the Company initiating design work;

b) 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

c) 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. **(T)**

(M)

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. **(M)** **(C)**

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. **(M)**

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. **(M)**

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. **(M)**

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 **(M)**

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 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. **(M)**

3) Where the Company provides trenching and backfilling for installation of applicable residential underground service laterals, the charges specified in Schedule 300 will apply. Estimated actual costs will apply where the Company provides trenching, and backfilling beyond the service lateral installation process. 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.

4) Where no other restrictions apply and the Applicant is only considering submersible transformers for aesthetic reasons, the Applicant may request the installation of submersible transformers instead of standard pad-mounted transformers. In this event, the cost set forth under the Transformers Section of Schedule 300 will be paid by the Applicant. **(M)**

C. **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. The cost set forth in Schedule 300 will be paid 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) **Long-Side Service Connection Charge**

Where the Applicant requests that the Company provide trenching and conduit for a long-side service connection the charge in Schedule 300 will apply.

4) **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.

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. (C)

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.

TABLE 4
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2022

CATEGORY	RATE SCHEDULE	Forecast SSEP18E19 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	809,036	7,555,010	$1,017,035,870	$1,082,623,855	$65,587,984	6.4%
Employee Discount				($1,110,239)	($1,163,909)	($53,670)	
Subtotal				$1,015,925,631	$1,081,459,946	$65,534,314	6.5%
Outdoor Area Lighting	15	0	14,480	$3,338,214	$3,601,934	$263,721	7.9%
General Service <30 kW	32	94,649	1,576,157	$202,510,144	$218,402,509	$15,892,365	7.8%
Opt. Time-of-Day G.S. >30 kW	38	377	31,528	$4,511,855	$4,508,372	($3,483)	-0.1%
Irrig. & Drain. Pump. < 30 kW	47	2,775	20,075	$4,207,083	$4,434,768	$227,685	5.4%
Irrig. & Drain. Pump. > 30 kW	49	1,405	61,430	$9,314,705	$10,063,139	$748,434	8.0%
General Service 31-200 kW	83	11,844	2,800,127	$286,246,767	$298,930,061	$12,683,294	4.4%
General Service 201-4,000 kW							
Secondary	85-S	1,304	2,134,357	$188,800,488	$188,854,043	$53,555	0.0%
Primary	85-P	177	612,588	$50,821,399	$50,885,400	$64,002	0.1%
Schedule 89 > 4 MW							
Primary	89-P	12	562,911	$38,860,057	$38,766,023	($94,034)	-0.2%
Subtransmission	89-T/75-T	5	53,697	$4,426,999	$4,528,377	$101,378	2.3%
Schedule 90	90-P	6	2,824,250	$179,775,368	$173,986,897	($5,788,471)	-3.2%
Street & Highway Lighting	91/95	184	41,836	$9,743,529	$11,194,969	$1,451,440	14.9%
Traffic Signals	92	16	2,576	$236,573	$207,389	($29,184)	-12.3%
COS TOTALS		921,790	18,291,022	$1,998,718,812	$2,089,823,827	$91,105,015	4.6%
Direct Access Service 201-4,000 kW							
Secondary	485-S	230	518,480	$13,982,262	$12,109,043	($1,873,219)	
Primary	485-P	57	373,475	$8,546,222	$6,723,918	($1,822,304)	
Direct Access Service > 4 MW							
Secondary	489-S	1	13,878	$279,362	$265,885	($13,477)	
Primary	489-P	14	1,007,674	$18,538,483	$11,487,778	($7,050,705)	
Subtransmission	489-T	3	243,839	$1,428,178	$1,479,373	$51,196	
New Load Direct Access Service > 10MW							
Primary	689-P	1	48,674	$640,811	$586,835	($53,976)	
DIRECT ACCESS TOTALS		306	2,206,020	43,415,318	32,652,832	($10,762,486)	-24.8%
COS AND DA CYCLE TOTALS		922,096	20,497,042	$2,042,134,129	$2,122,476,658	$80,342,529	3.9%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 7

	Net Monthly Bill		
kWh	Current Prices	Proposed Prices	Percent Difference
50	$18.34	$18.86	2.8%
100	$24.49	$25.46	3.9%
200	$36.78	$38.68	5.2%
250	$42.94	$45.32	5.5%
300	$49.07	$51.92	5.8%
400	$61.34	$65.15	6.2%
500	$73.65	$78.41	6.5%
600	$85.91	$91.64	6.7%
700	$98.18	$104.87	6.8%
780	$108.01	$115.45	6.9%
800	$110.46	$118.11	6.9%
850	$116.61	$124.72	6.9%
900	$122.76	$131.35	7.0%
1,000	$135.03	$144.56	7.1%
1,100	$148.84	$158.17	6.3%
1,200	$162.68	$171.77	5.6%
1,300	$176.49	$185.39	5.0%
1,400	$190.29	$198.99	4.6%
1,500	$204.14	$212.62	4.2%
1,600	$217.94	$226.22	3.8%
1,700	$231.76	$239.83	3.5%
1,800	$245.56	$253.43	3.2%
2,000	$273.21	$280.64	2.7%
2,300	$314.66	$321.46	2.2%
2,750	$376.87	$382.71	1.5%
3,000	$411.39	$416.71	1.3%
3,500	$480.50	$484.76	0.9%
4,000	$549.57	$552.79	0.6%
4,500	$618.68	$620.84	0.3%
5,000	$687.75	$688.86	0.2%
7,500	$1,033.22	$1,029.05	-0.4%
10,000	$1,378.64	$1,369.22	-0.7%

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	$80.47	$86.57	7.6%	$76.52	$82.62	8.0%
600	$92.42	$99.69	7.9%	$87.67	$94.94	8.3%
700	$104.37	$112.88	8.2%	$98.83	$107.34	8.6%
800	$116.32	$126.01	8.3%	$110.00	$119.69	8.8%
900	$128.28	$139.22	8.5%	$121.16	$132.10	9.0%
1,000	$140.22	$152.36	8.7%	$132.31	$144.45	9.2%
1,500	$200.01	$218.23	9.1%	$188.15	$206.37	9.7%
1,750	$229.92	$251.12	9.2%	$216.08	$237.28	9.8%
2,000	$259.76	$284.03	9.3%	$243.94	$268.21	10.0%
2,500	$319.54	$349.91	9.5%	$299.77	$330.13	10.1%
3,500	$439.08	$481.58	9.7%	$411.40	$453.89	10.3%
4,000	$498.83	$547.38	9.7%	$467.19	$515.73	10.4%
4,500	$558.62	$613.25	9.8%	$523.03	$577.66	10.4%
5,000	$618.37	$679.04	9.8%	$578.82	$639.49	10.5%
6,000	$709.50	$768.51	8.3%	$662.04	$721.05	8.9%
7,000	$800.65	$857.99	7.2%	$745.27	$802.61	7.7%
8,000	$891.79	$947.46	6.2%	$828.51	$884.18	6.7%
9,000	$982.92	$1,036 94	5.5%	$911.73	$965.74	5.9%
10,000	$1,074.07	$1,126.41	4.9%	$994.96	$1,047.31	5.3%
14,000	$1,438.63	$1,484 31	3.2%	$1,327.88	$1,373.56	3.4%
15,000	$1,529.76	$1,573.78	2.9%	$1,411.10	$1,455.13	3.1%
20,000	$1,985.46	$2,021.15	1.8%	$1,827.26	$1,862.95	2.0%
21,900	$2,158.63	$2,191.17	1.5%	$1,985.39	$2,017.94	1.6%

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	$89.78	$95.88	6.8%	$85.83	$91.93	7.1%
600	$101.73	$109.00	7.1%	$96.98	$104.25	7.5%
700	$113.69	$122.19	7.5%	$108.14	$116.65	7.9%
800	$125.63	$135.32	7.7%	$119.31	$129.00	8.1%
900	$137.59	$148.53	7.9%	$130.47	$141.41	8.4%
1,000	$149.53	$161.67	8.1%	$141.62	$153.76	8.6%
1,500	$209.32	$227.54	8.7%	$197.46	$215.68	9.2%
1,750	$239.23	$260.43	8.9%	$225.39	$246.59	9.4%
2,000	$269.07	$293.34	9.0%	$253.25	$277.52	9.6%
2,500	$328.85	$359.22	9.2%	$309.08	$339.44	9.8%
3,500	$448.39	$490.89	9.5%	$420.71	$463.21	10.1%
4,000	$508.14	$556.69	9.6%	$476.50	$525.05	10.2%
4,500	$567.92	$622.55	9.6%	$532.33	$586.96	10.3%
5,000	$627.68	$688.35	9.7%	$588.13	$648.80	10.3%
6,000	$718.82	$777.82	8.2%	$671.35	$730.36	8.8%
7,000	$809.96	$867.30	7.1%	$754.59	$811.93	7.6%
8,000	$901.10	$956.77	6.2%	$837.82	$893.49	6.6%
9,000	$992.23	$1,046 25	5.4%	$921.04	$975.05	5.9%
10,000	$1,083.38	$1,135.72	4.8%	$1,004.27	$1,056.62	5.2%
14,000	$1,447.94	$1,493 62	3.2%	$1,337.19	$1,382.87	3.4%
15,000	$1,539.07	$1,583 09	2.9%	$1,420.42	$1,464.44	3.1%
20,000	$1,994.77	$2,030.46	1.8%	$1,836.56	$1,872.26	1.9%
21,900	$2,167.94	$2,200.49	1.5%	$1,994.70	$2,027.25	1.6%

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	$48.65	$49.20	1.1%	$48.26	$48.81	1.1%
10	100	$58.93	$60.12	2.0%	$58.13	$59.33	2.1%
10	500	$141.67	$147.53	4.1%	$137.72	$143.58	4.3%
10	1,000	$234.68	$246.36	5.0%	$226.76	$238.44	5.2%
10	2,000	$420.73	$444.09	5.6%	$404.91	$428.27	5.8%
10	5,000	$978.90	$1,037 27	6.0%	$939.35	$997.72	6.2%
20	100	$58.93	$60.12	2.0%	$58.13	$59.33	2.1%
20	200	$79.65	$81.98	2.9%	$78.07	$80.39	3.0%
20	500	$141.67	$147.53	4.1%	$137.72	$143.58	4.3%
20	1,000	$245.03	$256.69	4.8%	$237.12	$248.78	4.9%
20	2,000	$431.08	$454.43	5.4%	$415.25	$438.60	5.6%
20	5,000	$989.24	$1,047 61	5.9%	$949.69	$1,008.06	6.1%
20	8,000	$1,547.41	$1,640 81	6.0%	$1,484.13	$1,577.53	6.3%
30	150	$69.32	$71.06	2.5%	$68.14	$69.88	2.5%
30	500	$141.67	$147.53	4.1%	$137.72	$143.58	4.3%
30	1,000	$245.03	$256.69	4.8%	$237.12	$248.78	4.9%
30	3,000	$627.48	$662.51	5.6%	$603.74	$638.77	5.8%
30	5,000	$999.59	$1,057 96	5.8%	$960.04	$1,018.41	6.1%
30	8,000	$1,557.76	$1,651.16	6.0%	$1,494.48	$1,587.88	6.2%
30	10,000	$1,929.87	$2,046 62	6.0%	$1,850.76	$1,967.51	6.3%
30	15,000	$2,860.14	$3,035 26	6.1%	$2,741.49	$2,916.61	6.4%

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	$863.43	$927.56	7.4%	$823.01	$887.14	7.8%
40%	35	10,220	$1,644.10	$1,772 32	7.8%	$1,563.25	$1,691.48	8.2%
60%	35	15,330	$2,424.76	$2,617.14	7.9%	$2,303.50	$2,495.87	8.4%
80%	35	20,440	$3,205.41	$3,461 92	8.0%	$3,043.72	$3,300.23	8.4%
20%	50	7,300	$1,213.51	$1,305.10	7.5%	$1,155.76	$1,247.36	7.9%
40%	50	14,600	$2,328.76	$2,511 99	7.9%	$2,213.27	$2,396.49	8.3%
60%	50	21,900	$3,443.99	$3,718 80	8.0%	$3,270.76	$3,545.56	8.4%
80%	50	29,200	$4,559.22	$4,925 65	8.0%	$4,328.23	$4,694.66	8.5%
20%	70	10,220	$1,680.30	$1,808 53	7.6%	$1,599.46	$1,727.68	8.0%
40%	70	20,440	$3,241.62	$3,498.14	7.9%	$3,079.94	$3,336.45	8.3%
60%	70	30,660	$4,802.97	$5,187.70	8.0%	$4,560.44	$4,945.16	8.4%
80%	70	40,880	$6,364.29	$6,877 27	8.1%	$6,040.92	$6,553.89	8.5%
20%	100	14,600	$2,380.49	$2,563.71	7.7%	$2,264.99	$2,448.22	8.1%
40%	100	29,200	$4,610.94	$4,977 38	7.9%	$4,379.96	$4,746.39	8.4%
60%	100	43,800	$6,841.43	$7,391 03	8.0%	$6,494.96	$7,044.56	8.5%
80%	100	58,400	$9,071.89	$9,804 69	8.1%	$8,609.92	$9,342.73	8.5%
20%	200	29,200	$4,714.39	$5,080 83	7.8%	$4,483.40	$4,849.84	8.2%
40%	200	58,400	$9,175.34	$9,908.14	8.0%	$8,713.37	$9,446.18	8.4%
60%	200	87,600	$13,636 30	$14,735 56	8.1%	$12,943 35	$14,042.61	8.5%
80%	200	116,800	$18,097 25	$19,562 88	8.1%	$17,173 32	$18,638.95	8.5%

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	$172.94	$172.83	-0.1%	$165.03	$164.92	-0.1%
3,000	$456.76	$456.42	-0.1%	$433.03	$432.69	-0.1%
5,000	$740.58	$740.01	-0.1%	$701.03	$700.45	-0.1%
7,000	$1,024.39	$1,023.60	-0.1%	$969.02	$968.23	-0.1%
10,000	$1,450.12	$1,448.98	-0.1%	$1,371.02	$1,369.88	-0.1%
13,000	$1,875.85	$1,874.37	-0.1%	$1,773.02	$1,771.53	-0.1%
14,000	$2,017.75	$2,016.17	-0.1%	$1,907.01	$1,905.42	-0.1%
16,000	$2,301.57	$2,299.75	-0.1%	$2,175.01	$2,173.18	-0.1%
21,000	$3,011.12	$3,008.73	-0.1%	$2,845.00	$2,842.61	-0.1%
25,000	$3,578.76	$3,575.91	-0.1%	$3,381.00	$3,378.15	-0.1%
30,000	$4,288.29	$4,284.88	-0.1%	$4,050.98	$4,047.57	-0.1%
35,000	$4,997.85	$4,993.85	-0.1%	$4,720.99	$4,716.99	-0.1%
40,000	$5,707.38	$5,702.83	-0.1%	$5,390.96	$5,386.41	-0.1%
45,000	$6,416.94	$6,411.80	-0.1%	$6,060.97	$6,055.83	-0.1%
50,000	$7,126.47	$7,120.79	-0.1%	$6,730.95	$6,725.27	-0.1%
75,000	$10,674.19	$10,665.65	-0.1%	$10,080.91	$10,072.37	-0.1%
100,000	$14,221.90	$14,210.52	-0.1%	$13,430.86	$13,419.48	-0.1%
150,000	$21,317.33	$21,300.28	-0.1%	$20,130.77	$20,113.72	-0.1%
200,000	$28,412.77	$28,390.00	-0.1%	$26,830.69	$26,807.92	-0.1%
300,000	$42,603.63	$42,569.49	-0.1%	$40,230.51	$40,196.37	-0.1%
400,000	$56,794.50	$56,748.97	-0.1%	$53,630.34	$53,584.81	-0.1%
500,000	$70,985.37	$70,928.47	-0.1%	$67,030.17	$66,973.27	-0.1%
750,000	$103,255.11	$103,084.43	-0.2%	$97,322.31	$97,151.63	-0.2%
1,000,000	$137,663.13	$137,435.54	-0.2%	$129,752.73	$129,525.14	-0.2%

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	$781.77	$821.15	5.0%	$729.80	$769.17	5.4%
30%	50	10,950	$1,269.86	$1,335.53	5.2%	$1,183.24	$1,248.91	5.5%
30%	75	16,425	$1,879.96	$1,978.46	5.2%	$1,750.04	$1,848.54	5.6%
30%	100	21,900	$2,490.03	$2,621.39	5.3%	$2,316.80	$2,448.15	5.7%
30%	135	29,565	$3,344.16	$3,521.47	5.3%	$3,110.29	$3,287.60	5.7%
30%	175	38,325	$4,320.35	$4,550.15	5.3%	$4,017.18	$4,246.98	5.7%
30%	200	43,800	$4,930.42	$5,193.09	5.3%	$4,583.95	$4,846.62	5.7%
50%	30	10,950	$1,129.38	$1,160.08	2.7%	$1,042.76	$1,073.46	2.9%
50%	50	18,250	$1,849.20	$1,900.35	2.8%	$1,704.83	$1,755.98	3.0%
50%	75	27,375	$2,748.92	$2,825.70	2.8%	$2,532.38	$2,609.15	3.0%
50%	100	36,500	$3,648.70	$3,751.03	2.8%	$3,359.97	$3,462.30	3.0%
50%	135	49,275	$4,908.37	$5,046.49	2.8%	$4,518.59	$4,656.71	3.1%
50%	175	63,875	$6,347.96	$6,527.08	2.8%	$5,842.68	$6,021.80	3.1%
50%	200	73,000	$7,247.72	$7,452.38	2.8%	$6,670.26	$6,874.92	3.1%
70%	30	15,330	$1,476.97	$1,498.96	1.5%	$1,355.70	$1,377.69	1.6%
70%	50	25,550	$2,428.50	$2,465.15	1.5%	$2,226.39	$2,263.04	1.6%
70%	75	38,325	$3,617.93	$3,672.90	1.5%	$3,314.76	$3,369.73	1.7%
70%	100	51,100	$4,807.33	$4,880.66	1.5%	$4,403.11	$4,476.43	1.7%
70%	135	68,985	$6,472.53	$6,571.52	1.5%	$5,926.83	$6,025.83	1.7%
70%	175	89,425	$8,375.60	$8,503.93	1.5%	$7,668.22	$7,796.55	1.7%
70%	200	102,200	$9,565.01	$9,711.67	1.5%	$8,756.57	$8,903.22	1.7%
90%	30	19,710	$1,824.57	$1,837.86	0.7%	$1,668.66	$1,681.95	0.8%
90%	50	32,850	$3,007.83	$3,029.97	0.7%	$2,747.97	$2,770.11	0.8%
90%	75	49,275	$4,486.91	$4,520.14	0.7%	$4,097.13	$4,130.36	0.8%
90%	100	65,700	$5,965.98	$6,010.29	0.7%	$5,446.26	$5,490.57	0.8%
90%	135	88,695	$8,036.69	$8,096.54	0.7%	$7,335.07	$7,394.92	0.8%
90%	175	114,975	$10,403.24	$10,480.82	0.7%	$9,493.74	$9,571.32	0.8%
90%	200	131,400	$11,882.28	$11,970.97	0.7%	$10,842.86	$10,931.55	0.8%

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

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Net Monthly Bill Proposed Prices	Percent Difference
30%	200	43,800	$4,983.72	$5,187.73	4.1%
30%	300	65,700	$7,061.75	$7,238.51	2.5%
30%	500	109,500	$11,217.90	$11,340.03	1.1%
30%	700	153,300	$15,374.02	$15,441.53	0.4%
30%	800	175,200	$17,452.04	$17,492.33	0.2%
30%	900	197,100	$19,530.13	$19,543.06	0.1%
30%	1,000	219,000	$21,608.18	$21,593.84	-0.1%
30%	1,500	328,500	$31,998.48	$31,847.65	-0.5%
30%	2,000	438,000	$42,388.77	$42,101.46	-0.7%
30%	4,000	876,000	$81,614.95	$80,682.05	-1.1%
50%	200	73,000	$7,015.14	$7,130.36	1.6%
50%	300	109,500	$10,108.93	$10,152.43	0.4%
50%	500	182,500	$16,296.48	$16,196.59	-0.6%
50%	700	255,500	$22,484.01	$22,240.72	-1.1%
50%	800	292,000	$25,577.78	$25,262.80	-1.2%
50%	900	328,500	$28,671.56	$28,284.87	-1.3%
50%	1,000	365,000	$31,765.32	$31,306.94	-1.4%
50%	1,500	547,500	$47,234.20	$46,417.31	-1.7%
50%	2,000	730,000	$62,703.06	$61,527.67	-1.9%
50%	4,000	1,460,000	$120,456.86	$117,681.33	-2.3%
70%	200	102,200	$9,046.55	$9,072.99	0.3%
70%	300	153,300	$13,156.07	$13,066.34	-0.7%
70%	500	255,500	$21,375.04	$21,053.12	-1.5%
70%	700	357,700	$29,594.00	$29,039.91	-1.9%
70%	800	408,800	$33,703.51	$33,033.26	-2.0%
70%	900	459,900	$37,812.98	$37,026.66	-2.1%
70%	1,000	511,000	$41,922.47	$41,020.04	-2.2%
70%	1,500	766,500	$60,426.80	$58,856.61	-2.6%
70%	2,000	1,022,000	$80,282.18	$78,102.41	-2.7%
70%	4,000	2,044,000	$159,236.78	$154,618.60	-2.9%
90%	200	131,400	$11,077.99	$11,015.61	-0.6%
90%	300	197,100	$16,203.21	$15,980.28	-1.4%
90%	500	328,500	$26,453.61	$25,909.68	-2.1%
90%	700	459,900	$36,704.01	$35,839.06	-2.4%
90%	800	525,600	$41,829.22	$40,803.75	-2.5%
90%	900	591,300	$46,954.43	$45,768.43	-2.5%
90%	1,000	657,000	$52,079.61	$50,733.14	-2.6%
90%	1,500	985,500	$75,078.76	$72,817.58	-3.0%
90%	2,000	1,314,000	$99,672.14	$96,571.05	-3.1%
90%	4,000	2,628,000	$198,016.69	$191,555.88	-3.3%

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

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Net Monthly Bill Proposed Prices	Percent Difference
30%	200	43,800	$4,796.98	$5,089.81	6.1%
30%	300	65,700	$6,828.24	$7,117.47	4.2%
30%	500	109,500	$10,890.75	$11,172.81	2.6%
30%	700	153,300	$14,953.22	$15,228.11	1.8%
30%	800	175,200	$16,984.46	$17,255.79	1.6%
30%	900	197,100	$19,015.70	$19,283.45	1.4%
30%	1,000	219,000	$21,046.96	$21,311.12	1.3%
30%	1,500	328,500	$31,203.22	$31,449.43	0.8%
30%	2,000	438,000	$41,359.43	$41,587.74	0.6%
30%	4,000	876,000	$79,649.38	$79,706.32	0.1%
50%	200	73,000	$6,789.44	$7,011.29	3.3%
50%	300	109,500	$9,816.94	$9,999.71	1.9%
50%	500	182,500	$15,871.90	$15,976.51	0.7%
50%	700	255,500	$21,926.85	$21,953.29	0.1%
50%	800	292,000	$24,954.31	$24,941.69	-0.1%
50%	900	328,500	$27,981.81	$27,930.09	-0.2%
50%	1,000	365,000	$31,009.27	$30,918.50	-0.3%
50%	1,500	547,500	$46,146.68	$45,860.50	-0.6%
50%	2,000	730,000	$61,284.05	$60,802.49	-0.8%
50%	4,000	1,460,000	$117,711.95	$116,282.69	-1.2%
70%	200	102,200	$8,781.91	$8,932.77	1.7%
70%	300	153,300	$12,805.61	$12,881.89	0.6%
70%	500	255,500	$20,853.06	$20,780.18	-0.3%
70%	700	357,700	$28,900.46	$28,678.45	-0.8%
70%	800	408,800	$32,924.16	$32,627.58	-0.9%
70%	900	459,900	$36,947.89	$36,576.72	-1.0%
70%	1,000	511,000	$40,971.58	$40,525.86	-1.1%
70%	1,500	766,500	$59,047.02	$58,141.22	-1.5%
70%	2,000	1,022,000	$78,473.50	$77,165.78	-1.7%
70%	4,000	2,044,000	$155,712.51	$152,797.08	-1.9%
90%	200	131,400	$10,774.35	$10,854.24	0.7%
90%	300	197,100	$15,794.31	$15,764.12	-0.2%
90%	500	328,500	$25,834.21	$25,583.87	-1.0%
90%	700	459,900	$35,874.08	$35,403.61	-1.3%
90%	800	525,600	$40,894.02	$40,313.49	-1.4%
90%	900	591,300	$45,913.94	$45,223.35	-1.5%
90%	1,000	657,000	$50,933.88	$50,133.24	-1.6%
90%	1,500	985,500	$73,406.74	$71,943.60	-2.0%
90%	2,000	1,314,000	$97,473.79	$95,422.98	-2.1%
90%	4,000	2,628,000	$193,713.09	$189,311.45	-2.3%

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

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Net Monthly Bill Proposed Prices	Percent Difference
30%	4,000	876,000	$79,096.04	$79,817.83	0.9%
30%	7,500	1,642,500	$143,838.15	$144,467.33	0.4%
30%	10,000	2,190,000	$190,038.16	$190,601.24	0.3%
30%	15,000	3,285,000	$282,438.26	$282,869.07	0.2%
30%	20,000	4,380,000	$374,838.36	$375,136.91	0.1%
50%	4,000	1,460,000	$115,720.75	$115,820.27	0.1%
50%	7,500	2,737,500	$212,393.23	$211,855.67	-0.3%
50%	10,000	3,650,000	$281,444.94	$280,452.35	-0.4%
50%	15,000	5,475,000	$419,548.43	$417,645.75	-0.5%
50%	20,000	7,300,000	$557,651.92	$554,839.14	-0.5%
70%	4,000	2,044,000	$152,283.47	$151,760.72	-0.3%
70%	7,500	3,832,500	$280,948.32	$279,244.00	-0.6%
70%	10,000	5,110,000	$372,851.73	$370,303.46	-0.7%
70%	15,000	7,665,000	$556,658.59	$552,422.41	-0.8%
70%	20,000	10,220,000	$740,465.47	$734,541.37	-0.8%
90%	4,000	2,628,000	$188,846.18	$187,701.16	-0.6%
90%	7,500	4,927,500	$349,503.40	$346,632.33	-0.8%
90%	10,000	6,570,000	$464,258.50	$460,154.58	-0.9%
90%	15,000	9,855,000	$693,768.76	$687,199.08	-0.9%
90%	20,000	13,140,000	$923,279.04	$914,243.58	-1.0%

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	$75,992.70	$77,211.53	1.6%
30%	7,500	1,642,500	$140,454.30	$141,164.60	0.5%
30%	10,000	2,190,000	$186,453.96	$186,801.03	0.2%
30%	15,000	3,285,000	$278,453.35	$278,073.95	-0.1%
30%	20,000	4,380,000	$370,452.74	$369,346.86	-0.3%
50%	4,000	1,460,000	$111,934.73	$112,821.28	0.8%
50%	7,500	2,737,500	$207,729.36	$207,816.63	0.0%
50%	10,000	3,650,000	$276,154.04	$275,670.41	-0.2%
50%	15,000	5,475,000	$413,003.46	$411,378.02	-0.4%
50%	20,000	7,300,000	$549,852.89	$547,085.63	-0.5%
70%	4,000	2,044,000	$147,814.76	$148,369.04	0.4%
70%	7,500	3,832,500	$275,004.41	$274,468.67	-0.2%
70%	10,000	5,110,000	$365,854.11	$364,539.79	-0.4%
70%	15,000	7,665,000	$547,553.58	$544,682.09	-0.5%
70%	20,000	10,220,000	$729,253.05	$724,824.39	-0.6%
90%	4,000	2,628,000	$183,694.79	$183,916.79	0.1%
90%	7,500	4,927,500	$342,279.47	$341,120.70	-0.3%
90%	10,000	6,570,000	$455,554.20	$453,409.18	-0.5%
90%	15,000	9,855,000	$682,103.69	$677,986.17	-0.6%
90%	20,000	13,140,000	$908,653.19	$902,563.15	-0.7%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Transmission
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Net Monthly Bill Proposed Prices	Percent Difference
30%	4,000	876,000	$72,227.69	$74,249.75	2.8%
30%	5,000	1,095,000	$89,210.38	$91,295.71	2.3%
30%	10,000	2,190,000	$173,813.83	$176,215.51	1.4%
30%	20,000	4,380,000	$343,020.73	$346,055.10	0.9%
30%	40,000	8,760,000	$681,434.53	$685,734.29	0.6%
30%	50,000	10,950,000	$850,641.43	$855,573.88	0.6%
30%	70,000	15,330,000	$1,189,055.24	$1,195,253.08	0.5%
50%	4,000	1,460,000	$107,728.70	$109,533.27	1.7%
50%	5,000	1,825,000	$133,509.13	$135,322.60	1.4%
50%	10,000	3,650,000	$262,411.35	$264,269.29	0.7%
50%	20,000	7,300,000	$520,215.76	$522,162.68	0.4%
50%	40,000	14,600,000	$1,035,824.60	$1,037,949.44	0.2%
50%	50,000	18,250,000	$1,293,629.02	$1,295,842.83	0.2%
50%	70,000	25,550,000	$1,809,237.86	$1,811,629.60	0.1%
70%	4,000	2,044,000	$143,167.70	$144,754.78	1.1%
70%	5,000	2,555,000	$177,807.90	$179,349.50	0.9%
70%	10,000	5,110,000	$351,008.87	$352,323.08	0.4%
70%	20,000	10,220,000	$697,410.79	$698,270.26	0.1%
70%	40,000	20,440,000	$1,390,214.67	$1,390,164.60	0.0%
70%	50,000	25,550,000	$1,736,616.60	$1,736,111.77	0.0%
70%	70,000	35,770,000	$2,429,420.47	$2,428,006.11	-0.1%
90%	4,000	2,628,000	$178,606.70	$179,976.29	0.8%
90%	5,000	3,285,000	$222,106.65	$223,376.39	0.6%
90%	10,000	6,570,000	$439,606.38	$440,376.87	0.2%
90%	20,000	13,140,000	$874,605.83	$874,377.83	0.0%
90%	40,000	26,280,000	$1,744,604.73	$1,742,379.75	-0.1%
90%	50,000	32,850,000	$2,179,604.18	$2,176,380.71	-0.1%
90%	70,000	45,990,000	$3,049,603.08	$3,044,382.63	-0.2%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 90 (30MWa), 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
80%	3,000	1,752,000	$125,043.25	$137,857.29	10.2%
80%	4,000	2,336,000	$164,454.22	$176,436.10	7.3%
80%	5,000	2,920,000	$203,772.07	$215,014.91	5.5%
80%	6,000	3,504,000	$243,089.92	$253,593.72	4.3%
80%	7,000	4,088,000	$282,407.77	$292,172.53	3.5%
80%	8,000	4,672,000	$321,725.62	$330,751.34	2.8%
80%	9,000	5,256,000	$361,043.47	$369,330.15	2.3%
90%	3,000	1,971,000	$137,886.57	$150,338.12	9.0%
90%	4,000	2,628,000	$181,578.64	$193,077.20	6.3%
90%	5,000	3,285,000	$225,177.59	$235,816.29	4.7%
90%	6,000	3,942,000	$268,776.55	$278,555.38	3.6%
90%	7,000	4,599,000	$312,375.50	$321,294.47	2.9%
90%	8,000	5,256,000	$355,974.46	$364,033.56	2.3%
90%	9,000	5,913,000	$399,573.42	$406,772.64	1.8%

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	$9,836,645.42	$9,493,132.41	-3.5%
80%	260,000	151,840,000	$10,229,823.93	$9,871,972.87	-3.5%
80%	270,000	157,680,000	$10,623,002.43	$10,250,813.34	-3.5%
80%	280,000	163,520,000	$11,016,180.94	$10,629,653.79	-3.5%
80%	290,000	169,360,000	$11,409,359.45	$11,008,494.26	-3.5%
80%	300,000	175,200,000	$11,802,537.95	$11,387,334.72	-3.5%
80%	310,000	181,040,000	$12,195,716.45	$11,766,175.18	-3.5%
90%	250,000	164,250,000	$10,906,921.85	$10,511,490.33	-3.6%
90%	260,000	170,820,000	$11,342,911.41	$10,931,065.10	-3.6%
90%	270,000	177,390,000	$11,778,900.97	$11,350,639.88	-3.6%
90%	280,000	183,960,000	$12,214,890.53	$11,770,214.66	-3.6%
90%	290,000	190,530,000	$12,650,880.09	$12,189,789.44	-3.6%
90%	300,000	197,100,000	$13,086,869.66	$12,609,364.22	-3.6%
90%	310,000	203,670,000	$13,522,859.21	$13,028,939.00	-3.7%

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2022 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
Schedule 7	$482,216	$24,662	$798	($3,110)	$22,350	$43,074	$2,313	$45,387	$28,468	$11,333	$77,674	$181,045	$298,520
Schedule 15	$691	$85	$1	($6)	$80	$42	$3	$45	$55	$22	$156	$208	$441
Schedule 32	$90,338	$4,665	$143	($649)	$4,159	$7,121	$433	$7,554	$4,751	$1,891	$15,626	$30,766	$53,034
Schedule 38	$1,670	$96	$3	($13)	$85	$126	$8	$134	$153	$61	$517	$1,172	$1,903
Schedule 47	$1,282	$98	$2	($8)	$91	$92	$6	$98	$162	$65	$534	$1,055	$1,815
Schedule 49	$4,033	$222	$6	($25)	$203	$284	$19	$303	$529	$211	$1,787	$1,970	$4,497
Schedule 83													
Secondary	$159,289	$6,203	$252	($1,153)	$5,302	$12,566	$764	$13,330	$8,725	$3,473	$29,441	$25,210	$66,849
Schedule 85													
Secondary		$4,024	$229	($1,092)	$3,161								
Primary		$1,251	$84	($406)	$929								
Class Total	$149,995					$11,470	$710	$12,180	$9,486	$3,776	$23,839	$8,376	$45,477
Schedule 89													
Secondary		$3	$1	($6)	($1)						$97		$97
Primary		$1,059	$134	($666)	$526						$2,627		$2,627
Subtransmission		$131	$24	($122)	$33						$813		$813
Class Total	$32,382					$2,901	$201	$3,102	$3,815	$1,843			$5,658
Schedule 90-P	$138,445	$3,710	$219	($1,162)	$2,766	$9,300	$645	$9,945	$5,566	$2,159	$2,745		$10,471
Schedules 91 & 95	$2,024	$235	$3	($17)	$221	$128	$10	$138	$158	$63	$451	$632	$1,305
Schedules 92	$131	$4	$0	($1)	$3	$9	$1	$9	$4	$2	$13	$6	$25
Totals	$1,062,497	$46,447	$1,899	($8,436)	$39,910	$87,112	$5,113	$92,225	$61,873	$24,900	$156,321	$250,441	$493,534

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2022 COSTS TO RATE SCHEDULES ($000)

	Dist. Customer-Related TSM		Uncollectibles		Metering		Billing		Other Consumer		Subtotal				Total
Grouping	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Fixed Costs	Subtotal	Cost Allocations
Schedule 7	$108,155	$0	$4,979	$0	$4,147	$0	$31,215	$0	$92,167	$0	$240,664	$0		$240,664	$1,089,137
Schedule 15	$153		$9		$0		$185		$491		$839	$0	$1,666	$2,505	$3,763
Schedule 32	$15,223	$18,835	$241	$185	$693	$531	$2,081	$1,596	$6,514	$4,994	$24,753	$26,142		$50,895	$205,980
Schedule 38	$16	$269	$0	$0	$5	$29	$8	$50	$7	$47	$35	$394		$430	$4,222
Schedule 47	$22	$328	$21	$215	$3	$33	$9	$93	$27	$276	$81	$945		$1,026	$4,312
Schedule 49	$4	$360	$0	$15	$0	$33	$3	$213	$2	$153	$9	$774		$783	$9,820
Schedule 83															
Secondary	$438	$16,685	$15	$223	$37	$541	$124	$1,816	$569	$8,351	$1,182	$27,616		$28,799	$273,569
Schedule 85															
Secondary		$5,013		$48		$139		$253		$9,379	$0	$14,831		$14,831	
Primary		$641		$7		$21		$39		$1,430	$0	$2,138		$2,138	$228,711
Schedule 89															
Secondary		$24		$0		$0		$0		$40	$0	$65		$65	
Primary		$78		$10		$0		$4		$1,085	$0	$1,178		$1,178	
Subtransmission		$219		$3		$0		$1		$322	$0	$545		$545	$47,026
Schedule 90-P		$17		$0		$0		$1		$1,488	$0	$1,507		$1,507	$1,507
Schedules 91 & 95	$1,065			$0		$0	$79		$10		$1,154	$0	$5,529	$6,683	$10,370
Schedule 92		$13		$0		$0		$5		$1	$0	$20		$20	$189
Totals	$125,076	$42,484	$5,266	$707	$4,886	$1,327	$33,704	$4,070	$99,787	$27,565	$268,718	$76,153	$7,195	$352,067	$1,878,607

Reconcile to Ratespread ($161,626.0)

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2022

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	$240,664	809,036	Customers	$24.79	per cust. per mo.		$240,672
Three-Phase	$0	0	Customers	$0.00	per cust. per mo.		$0
Trans. & Rel. Serv. Charge	$45,387	7,555,010	MWh	6.01	mills/kWh		$45,406
Distribution Charge	$298,520	7,555,010	MWh	39.51	mills/kWh		$298,498
Franchise Fees & Other	$22,350	7,555,010	MWh	2.96	mills/kWh		$22,363
Energy Charge	$482,216	7,555,010	MWh	63.83	mills/kWh		$482,236
Subtotal	$1,089,137						$1,089,175
Pricing							
Functional Costs							
Basic Charge							
Single-Phase		809,036	Customers	$11.00	per cust. per mo.		$106,793
Three-Phase		0	Customers	$11.00	per cust. per mo.		$0
Trans. & Rel. Serv. Charge		7,555,010	MWh	6.01	mills/kWh		$45,406
Distribution Charge		7,555,010	MWh	54.17	mills/kWh		$409,255
System Usage Charge Calculation							
Franchise Fees & Other		7,555,010	MWh	2.96	mills/kWh		$22,363
Cust Impact Offset		7,555,010	MWh	(0.65)	mills/kWh		($4,907)
System Usage Charge		7,555,010	MWh	2.31	mills/kWh		$17,456
Energy Charge							
Block 1 (First 500 kWh)		4,261,840	MWh	66.35	mills/kWh		$282,773
Block 2 (501-1,000 kWh)		2,162,066	MWh	66.35	mills/kWh		$143,453
Block 3 (Over 1,000 kWh)		1,131,104	MWh	69.95	mills/kWh		$79,121
Subtotal							$1,084,256
					w/o CIO		$1,089,163
SCHEDULE 15							
Outdoor Area Lighting							
Allocations							
Functional Costs							
Basic Charge	$839	8,969	Customers	$7.80	per cust. per mo.		$839
Trans. & Rel. Serv. Charge	$45	14,480	MWh	3.12	mills/kWh		$45
Distribution Charge	$441	14,480	MWh	30.46	mills/kWh		$441
Franchise Fees & Other	$80	14,480	MWh	5.54	mills/kWh		$80
Energy Charge	$691	14,480	MWh	47.72	mills/kWh		$691
Fixed Charges	$1,666	14,480	MWh				$1,666
Subtotal	$3,763						$3,763
Pricing							
Functional Costs							
Trans. & Rel. Serv. Charge		14,480	MWh	3.12	mills/kWh		$45
Distribution Charge		14,480	MWh	88.42	mills/kWh		$1,280
System Usage Charge Calc							
Franchise Fees & Other		14,480	MWh	5.54	mills/kWh		$80
Cust Impact Offset		14,480	MWh	(22.09)	mills/kWh		($320)
System Usage Charge		14,480	MWh	(16.55)	mills/kWh		($240)
Energy Charge		14,480	MWh	47.72	mills/kWh		$691
Fixed Charges		14,480	MWh				$1,666
Subtotal							$3,443
					w/o CIO		$3,763

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2022

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	$24,753	53,573	Customers	$38.50	per cust. per mo.		$24,751
Three-Phase	$26,142	41,076	Customers	$53.04	per cust. per mo.		$26,144
Trans. & Rel. Serv. Charge	$7,554	1,576,157	MWh	4.79	mills/kWh		$7,550
Distribution Charge	$53,034	1,576,157	MWh	33.65	mills/kWh		$53,038
Franchise Fees & Other	$4,159	1,576,157	MWh	2.64	mills/kWh		$4,161
Energy Charge	$90,338	1,576,157	MWh	57.32	mills/kWh		$90,345
Subtotal	$205,980						$205,989
Pricing							
Functional Costs							
Basic Charge							
Single-Phase		53,573	Customers	$20.00	per cust. per mo.		$12,858
Three-Phase		41,076	Customers	$29.00	per cust. per mo.		$14,294
Trans. & Rel. Serv. Charge		1,576,157	MWh	4.79	mills/kWh		$7,550
Distribution Charge							
First 5 MWh		1,379,636	MWh	53.79	mills/kWh		$74,211
Over 5 MWh		196,521	MWh	13.00	mills/kWh		$2,555
System Usage Charge Calc							
Franchise Fees & Other		1,576,157	MWh	2.64	mills/kWh		$4,161
Cust Impact Offset		1,576,157	MWh	(2.35)	mills/kWh		($3,704)
System Usage Charge		1,576,157	MWh	0.29	mills/kWh		$457
Energy Charge		1,576,157	MWh	57.32	mills/kWh		$90,345
Subtotal							$202,270
					w/o CIO		$205,973
SCHEDULE 38							
Time-of-Day G.S. >30 kW							
Allocations							
Functional Costs							
Basic							
Single-Phase	$35	51	Customers	$57.40	per cust. per mo.		$35
Three-Phase	$394	326	Customers	$100.82	per cust. per mo.		$394
Trans. & Rel. Serv. Charge	$134	31,528	MWh	4.25	per cust. per mo.		$134
Distribution Charges	$1,903	31,528	MWh	60.36	per cust. per mo.		$1,903
Franchise Fees & Other	$85	31,528	MWh	2.71	mills/kWh		$85
Energy Charge	$1,670	31,528	MWh	52.98	mills/kWh		$1,670
Subtotal	$4,222						$4,223
Pricing							
Functional Costs							
Basic							
Single-Phase		51	Customers	$30.00	per cust. per mo.		$18
Three-Phase		326	Customers	$30.00	per cust. per mo.		$117
Trans. & Rel. Serv. Charge		31,528	MWh	4.25	mills/kWh		$134
Distribution Charges		31,528	MWh	68.71	mills/kWh		$2,166
System Usage Charge							
Franchise Fees & Other		31,528	MWh	2.71	mills/kWh		$85
Cust Impact Offset		31,528	MWh	0.00	mills/kWh		$0
System Usage Charge		31,528	MWh	2.71	mills/kWh		$85
Energy Charge Calc							
On-Peak (special)		17,389	MWh	59.71	mills/kWh		$1,038
Off-Peak		14,139	MWh	44.71	mills/kWh		$632
Reactive Demand Charge		60,755	kVar	0.50	kVar		$30
Subtotal							$4,222
					w/o CIO		$4,222

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2022

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	o	Annual Revenue ($000)
SCHEDULE 47							
Irrig. & Drain. Pump. - < 30 kW							
Allocations							
Functional Costs							
Basic Charge							
Single-Phase	$81	245	Customers	$55.33	per cust. per summ. mo.		$81
Three-Phase	$945	2,530	Customers	$62.23	per cust. per summ. mo.		$945
Trans. & Rel. Serv. Charge	$98	20,075	MWh	4.89	mills/kWh		$98
Distribution Charges	$1,815	20,075	MWh	90.43	mills/kWh		$1,815
Franchise Fees & Other	$91	20,075	MWh	4.55	mills/kWh		$91
Energy Charge	$1,282	20,075	MWh	63.84	mills/kWh		$1,282
Subtotal	$4,312						$4,312
Pricing							
Functional Costs							
Basic Charge							
Single-Phase		245	Customers	$37.00	per cust. per summ. mo.		$54
Three-Phase		2,530	Customers	$37.00	per cust. per summ. mo.		$562
Trans. & Rel. Serv. Charge		20,075	MWh	4.89	mills/kWh		$98
Distribution Charge Calc							
First 50 kWh per kW		4,929	MWh	125.85	mills/kWh		$620
Over 50 kWh per kW		15,146	MWh	105.85	mills/kWh		$1,603
System Usage Charge Calc							
Franchise Fees & Other		20,075	MWh	4.55	mills/kWh		$91
Cust Impact Offset		20,075	MWh	0.00	mills/kWh		$0
System Usage Charge		20,075	MWh	4.55	mills/kWh		$91
Energy Charge		20,075	MWh	63.84	mills/kWh		$1,282
Reactive Demand Charge		3,123	kVar	$0.50	kVar		$2
Subtotal with Consumer Impact Offset							$4,311
					w/o CIO		$4,312
SCHEDULE 49							
Irrig. & Drain. Pump. - > 30 kW							
Allocations							
Functional Costs							
Basic							
Single-Phase	$9	17	Customers	$90.34	per cust. per summ. mo.		$9
Three-Phase	$774	1,388	Customers	$92.90	per cust. per summ. mo.		$774
Trans. & Rel. Serv. Charge	$303	61,430	MWh	4.93	mills/kWh		$303
Distribution Charges	$4,497	61,430	MWh	73.20	mills/kWh		$4,497
Franchise Fees & Other	$203	61,430	MWh	3.31	mills/kWh		$203
Energy Charge	$4,033	61,430	MWh	65.66	mills/kWh		$4,034
Subtotal	$9,820						$9,819
Pricing							
Functional Costs							
Basic Charge							
Single-Phase		17	Customers	$45.00	per cust. per summ. mo.		$5
Three-Phase		1,388	Customers	$45.00	per cust. per summ. mo.		$375
Trans. & Rel. Serv. Charge		61,430	MWh	4.93	mills/kWh		$303
Distribution Charge Calc							
First 50 kWh per kW		11,380	MWh	95.86	mills/kWh		$1,091
Over 50 kWh per kW		50,050	MWh	75.86	mills/kWh		$3,797
System Usage Charge Calc							
Franchise Fees & Other		61,430	MWh	3.31	mills/kWh		$203
Cust Impact Offset		61,430	MWh	0.00	mills/kWh		$0
System Usage Charge		61,430	MWh	3.31	mills/kWh		$203
Energy Charge		61,430	MWh	65.66	mills/kWh		$4,034
Reactive Demand Charge		25,374	kVar	0.50	kVar		$13
Subtotal with Consumer Impact Offset							$9,819
					w/o CIO		$9,819

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2022

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	$1,182	755	Customers	$130.44	per cust, per mo.		$1,182
Three-Phase Secondary	$27,616	11,089	Customers	$207.54	per cust, per mo.		$27,617
Transmission & Related Service Charge	$13,330	8,356,843	kW demand	$1.60	per kW demand		$13,371
Distribution Charges							
Feeder Backbone	$29,441	10,803,725	kW faccap	$2.73	per kW faccap		$29,494
Feeder Local Facilities	$25,210	10,803,725	kW faccap	$2.33	per kW faccap		$25,173
Subtransmission Charge	$3,473	8,356,843	kW demand	$0.42	per kW demand		$3,510
Substation Charge	$8,725	8,356,843	kW demand	$1.04	per kW demand		$8,691
Secondary Franchise Fees & Other	$5,302	2,800,127	MWh	1.89	mills/kWh		$5,292
Secondary COS Energy Charge	$159,289	2,800,127	MWh	56.89	mills/kWh		$159,299
Subtotal	$273,569						$273,629
Pricing							
Functional Costs							
Basic Charge							
Secondary Single-Phase		755	Customers	$35.00	per cust, per mo.		$317
Secondary Three-Phase		11,089	Customers	$45.00	per cust, per mo.		$5,988
Trans. & Rel. Serv. Charge							
On-peak		8,316,437	kW demand	$1.86	per kW demand		$15,469
Off-peak		40,406	kW demand	$0.00	per kW demand		$0
Distribution Charges							
Secondary Facilities Charge							
First 30 kW		4,263,960	kW faccap	$5.12	<= 30 kW faccap		$21,831
Over 30 kW		6,539,765	kW faccap	$5.02	> 30 kW faccap		$32,830
Secondary Demand Charge							
On-peak		8,316,437	kW demand	$1.60	per kW demand		$13,306
Off-peak		40,406	kW demand	$0.00	per kW demand		$0
Secondary System Usage Charge Calc							
Franchise Fees & Other		2,800,127	MWh	1.89	mills/kWh		$5,292
Cust Impact Offset		2,800,127	MWh	0.00	mills/kWh		$0
Rate Design		2,800,127	MWh	6.75	mills/kWh		$18,901
System Usage Charge		2,800,127	MWh	8.64	mills/kWh		$24,193
COS Energy Charge							
On-peak		1,845,558	MWh	62.00	mills/kWh		$114,425
Off-peak		954,569	MWh	47.00	mills/kWh		$44,865
Reactive Demand Charge		649,134	kVar	$0.50	kVar		$325
Subtotal							$273,548
					w/o CIO		$273,548

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2022

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	o	Annual Revenue ($000)
SCHEDULE 85							
General Service 201-4,000 kW							
Allocations							
Functional Costs							
Basic Charge							
Secondary	$14,831	1,534	Customers	$805.91	per cust, per mo.		$14,831
Primary	$2,138	234	Customers	$762.15	per cust, per mo.		$2,138
Transmission & Related Service Charge	$12,180	7,017,722	kW on-peak	$1.74	per kW demand		$12,211
Distribution Charges							
Feeder Backbone	$23,839	10,904,442	kW faccap	$2.19	per kW faccap		$23,881
Feeder Local Facilities	$8,376	10,904,442	kW faccap	$0.77	per kW faccap		$8,396
Subtransmission Charge	$3,776	8,786,474	kW on-peak	$0.43	per kW on-peak demand		$3,778
Substation Charge	$9,486	8,786,474	kW on-peak	$1.08	per kW on-peak demand		$9,489
Secondary Franchise Fees & Other	$3,161	2,652,837	MWh	1.19	mills/kWh		$3,157
Primary Franchise Fees & Other	$929	986,063	MWh	0.94	mills/kWh		$927
COS Energy Charge	$149,995	2,746,945	MWh	54.60	mills/kWh		$149,983
Subtotal	$228,711						$228,792
Pricing							
Functional Costs							
Basic Charge							
Secondary		1,534	Customers	$810.00	per cust, per mo.		$14,906
Primary		234	Customers	$760.00	per cust, per mo.		$2,132
Secondary Trans. & Rel. Serv. Charge		5,387,490	kW on-peak	$1.86	per kW demand		$10,021
Primary Trans. & Rel. Serv. Charge		1,630,232	kW on-peak	$1.84	per kW demand		$3,000
Distribution Charges							
Secondary Facilities Charge							
First 200 kW		3,680,424	kW faccap	$3.48	per kW faccap		$12,808
Over 200 kW		4,330,335	kW faccap	$2.28	per kW faccap		$9,873
Primary Facilities Charge							
First 200 kW		558,596	kW faccap	$3.45	per kW faccap		$1,927
Over 200 kW		2,335,087	kW faccap	$2.25	per kW faccap		$5,254
Secondary Demand Charge		6,455,957	kW on-peak	$1.60	per kW demand		$10,330
Primary Demand Charge		2,330,517	kW on-peak	$1.58	per kW demand		$3,682
Secondary System Usage Charge Calc							
COS Franchise Fees & Other		2,134,357	MWh	1.44	mills/kWh		$3,073
Cust Impact Offset		2,134,357	MWh	1.64	mills/kWh		$3,500
COS System Usage Charge		2,134,357	MWh	3.08	mills/kWh		$6,574
DA Franchise Fees & Other		518,480	MWh	0.16	mills/kWh		$83
Cust Impact Offset		518,480	MWh	1.64	mills/kWh		$850
DA System Usage Charge		518,480	MWh	1.80	mills/kWh		$933
Primary System Usage Charge Calc							
COS Franchise Fees & Other		612,588	MWh	1.42	mills/kWh		$870
Cust Impact Offset		612,588	MWh	1.64	mills/kWh		$1,005
COS System Usage Charge		612,588	MWh	3.06	mills/kWh		$1,875
DA Franchise Fees & Other		373,475	MWh	0.16	mills/kWh		$60
Cust Impact Offset		373,475	MWh	1.64	mills/kWh		$612
DA System Usage Charge		373,475	MWh	1.80	mills/kWh		$672
Secondary COS Energy Charge							
On-peak		1,395,753	MWh	60.01	mills/kWh		$83,759
Off-peak		738,604	MWh	45.01	mills/kWh		$33,245
Primary COS Energy Charge							
On-peak		386,572	MWh	59.41	mills/kWh		$22,966
Off-peak		226,015	MWh	44.41	mills/kWh		$10,037
Reactive Demand Charge		1,453,975	kVar	0.50	kVar		$727
Subtotal							$234,721
					w/o CIO		$228,753

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2022

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	$65	1	Customers	$5,378.53	per cust, per mo.		$65
Primary Basic Charge	$1,178	27	Customers	$3,634.46	per cust, per mo.		$1,178
Subtransmission Basic Charge	$545	8	Customers	$5,678.43	per cust, per mo.		$545
Transmission & Related Service Charge	$3,102	1,301,452	kW on-peak	$2.38	per kW on-peak demand		$3,097
Distribution Charges							
Feeder Backbone	$3,538	4,109,578	kW faccap	$0.86	per kW faccap		$3,534
Feeder Local Facilities							$0
Subtransmission Demand Charge	$1,843	3,561,705	kW on-peak	$0.52	per kW on-peak demand		$1,852
Substation Demand Charge	$3,815	2,859,913	kW on-peak	$1.33	per kW on-peak demand		$3,804
Secondary Franchise Fees & Other	($1)	13,878	MWh	(0.10)	mills/kWh		($1)
Primary Franchise Fees & Other	$526	1,619,259	MWh	0.32	mills/kWh		$518
Subtransmission Franchise Fees & Othe	$33	297,536	MWh	0.11	mills/kWh		$33
Energy Charge	$32,382	616,608	MWh	52.52	mills/kWh		$32,384
Subtotal	$47,026						$47,008
Pricing							
Functional Costs							
Secondary Basic Charge		1	Customers	$5,380.00	per cust, per mo.		$65
Primary Basic Charge		27	Customers	$3,630.00	per cust, per mo.		$1,176
Subtransmission Basic Charge		8	Customers	$5,680.00	per cust, per mo.		$545
Secondary Trans. & Rel. Serv. Charge		0	kW on-peak	$1.86	per kW on-peak demand		$0
Primary Trans. & Rel. Serv. Charge		1,063,151	kW on-peak	$1.84	per kW on-peak demand		$1,956
Subtransmission Trans. & Rel. Serv. Charge		238,301	kW on-peak	$1.81	per kW on-peak demand		$431
Distribution Charges							
Secondary Facilities Charge							
First 1,000 kW		12,000	kW faccap	$1.35	per kW faccap		$16
1,001-4,000 kW		47,436	kW faccap	$1.35	per kW faccap		$64
Greater than 4,000 kW		13,397	kW faccap	$1.04	per kW faccap		$14
Primary Facilities Charge							
First 1,000 kW		324,000	kW faccap	$1.34	per kW faccap		$434
1,001-4,000 kW		962,066	kW faccap	$1.34	per kW faccap		$1,289
Greater than 4,000 kW		1,914,505	kW faccap	$1.03	per kW faccap		$1,972
Subtransmission Facilities Charge							
First 1,000 kW		96,000	kW faccap	$1.34	per kW faccap		$129
1,001-4,000 kW		269,528	kW faccap	$1.34	per kW faccap		$361
Greater than 4,000 kW		470,646	kW faccap	$1.03	per kW faccap		$485
Secondary Demand Charge		47,761	kW on-peak	$1.60	per kW on-peak demand		$76
Primary Demand Charge		2,812,152	kW on-peak	$1.58	per kW on-peak demand		$4,443
Subtransmission Demand Charge		701,792	kW on-peak	$0.50	per kW on-peak demand		$351
Secondary System Usage Charge Calc							
COS Franchise Fees & Other		0	MWh	1.15	mills/kWh		$0
Cust Impact Offset		0	MWh	1.37	mills/kWh		$0
COS System Usage Charge		0	MWh	2.52	mills/kWh		$0
DA Franchise Fees & Other		13,878	MWh	(0.11)	mills/kWh		($2)
Cust Impact Offset		13,878	MWh	1.37	mills/kWh		$19
DA System Usage Charge		13,878	MWh	1.26	mills/kWh		$17
Primary System Usage Charge Calc							
COS Franchise Fees & Other		562,911	MWh	1.14	mills/kWh		$642
Cust Impact Offset		562,911	MWh	1.37	mills/kWh		$771
COS System Usage Charge		562,911	MWh	2.51	mills/kWh		$1,413
DA Franchise Fees & Other		1,056,348	MWh	(0.10)	mills/kWh		($106)
Cust Impact Offset		1,056,348	MWh	1.37	mills/kWh		$1,447
DA System Usage Charge		1,056,348	MWh	1.27	mills/kWh		$1,342
Subtransmission System Usage Charge Calc							
COS Franchise Fees & Other		53,697	MWh	1.12	mills/kWh		$60
Cust Impact Offset		53,697	MWh	1.37	mills/kWh		$74
COS System Usage Charge		53,697	MWh	2.49	mills/kWh		$134
DA Franchise Fees & Other		243,839	MWh	(0.11)	mills/kWh		($27)
Cust Impact Offset		243,839	MWh	1.37	mills/kWh		$334
DA System Usage Charge		243,839	MWh	1.26	mills/kWh		$307
Secondary Energy Charge							
On-peak		0	MWh	59.14	mills/kWh		$0

PORTLAND GENERAL ELECTRIC
RATE DESIGN
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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	o	Annual Revenue ($000)
Off-peak		0	MWh	44.14	mills/kWh		$0
Primary Energy Charge							
On-peak		334,580	MWh	58.56	mills/kWh		$19,593
Off-peak		228,330	MWh	43.56	mills/kWh		$9,946
Subtransmission Energy Charge							
On-peak		35,654	MWh	57.97	mills/kWh		$2,067
Off-peak		18,043	MWh	42.97	mills/kWh		$775
Reactive Demand Charge		578,503	kVar	0.50	kVar		$289
Subtotal							$49,691
					w/o CIO		$47,046

PORTLAND GENERAL ELECTRIC
RATE DESIGN
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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	$1,507	6	Customers	$20,926.87	per cust, per mo.		$1,507
Transmission & Related Service Charge	$9,945	4,172,523	kW on-peak	$2.38	per kW on-peak demand		$9,931
Distribution Charges							
Feeder Backbone	$2,745	4,366,656	kW faccap	$0.63	per kW faccap		$2,751
Subtransmission Demand Charge	$2,159	4,172,523	kW on-peak	$0.52	per kW on-peak demand		$2,170
Substation Demand Charge	$5,566	4,172,523	kW on-peak	$1.33	per kW on-peak demand		$5,549
Primary Franchise Fees & Other	$2,766	2,824,250	MWh	0.98	mills/kWh		$2,768
Energy Charge	$138,445	2,824,250	MWh	49.02	mills/kWh		$138,445
Subtotal	$163,133						$163,120
Pricing							
Functional Costs							
Primary Basic Charge		6	Customers	$20,900.00	per cust, per mo.		$1,505
Primary Trans. & Rel. Serv. Charge		4,172,523	kW on-peak	$1.84	per kW on-peak demand		$7,677
Distribution Charges							
Primary Facilities Charge							
First 4,000 kW		288,000	kW faccap	$1.70	per kW faccap		$490
Over 4,000 kW		4,078,656	kW faccap	$1.39	per kW faccap		$5,669
Primary Demand Charge		4,172,523	kW on-peak	$1.58	per kW on-peak demand		$6,593
Primary System Usage Charge Calc							
COS Franchise Fees & Other		2,824,250	MWh	0.98	mills/kWh		$2,768
Cust Impact Offset		2,824,250	MWh	0.00	mills/kWh		$0
COS System Usage Charge		2,824,250	MWh	0.98	mills/kWh		$2,768
Primary Energy Charge							
On-peak		1,624,613	MWh	55.39	mills/kWh		$89,987
Off-peak		1,199,636	MWh	40.39	mills/kWh		$48,453
Reactive Demand Charge		9,114	kVar	$0.50	kVar		$5
							$163,147
					w/o CIO		$163,147

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2022

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	o	Annual Revenue ($000)
SCHEDULES 91 & 95							
Street & Highway Lighting							
Allocations							
Functional Costs							
Basic Charge	$1,154	184	Customers	$522.66	per cust, per mo.		$1,154
Trans. & Rel. Serv. Charge	$138	41,836	MWh	3.29	mills/kWh		$138
Distribution Charge	$1,305	41,836	MWh	31.19	mills/kWh		$1,305
Franchise Fees & Other	$221	41,836	MWh	5.27	mills/kWh		$220
COS Energy Charge	$2,024	41,836	MWh	48.39	mills/kWh		$2,024
Fixed Charges	$5,529						$5,529
Subtotal	$10,370						$10,370
Pricing							
Functional Costs							
Trans. & Rel. Serv. Charge		41,836	MWh	3.29	mills/kWh		$138
Distribution Charge		41,836	MWh	58.78	mills/kWh		$2,459
System Usage Charge Calc							
Franchise Fees & Other		41,836	MWh	5.27	mills/kWh		$220
Cust Impact Offset		41,836	MWh	7.65	mills/kWh		$320
System Usage Charge		41,836	MWh	12.92	mills/kWh		$541
COS Energy Charge		41,836	MWh	48.39	mills/kWh		$2,024
Fixed Charges		41,836	MWh				$5,529
Subtotal							$10,691
					w/o CIO		$10,371
SCHEDULE 92							
Traffic Signals							
Allocations							
Functional Costs							
Basic Charge	$20	16	Customers	$101.95	per cust, per mo.		$20
Trans. & Rel. Serv. Charge	$9	2,576	MWh	3.66	mills/kWh		$9
Distribution Charge	$25	2,576	MWh	9.76	mills/kWh		$25
Franchise Fees & Other	$3	2,576	MWh	1.33	mills/kWh		$3
COS Energy Charge	$131	2,576	MWh	50.98	mills/kWh		$131
Subtotal	$189						$189
Pricing							
Functional Costs							
Trans. & Rel. Serv. Charge		2,576	MWh	3.66	mills/kWh		$9
Distribution Charge		2,576	MWh	17.36	mills/kWh		$45
System Usage Charge Calc							
Franchise Fees & Other		2,576	MWh	1.33	mills/kWh		$3
Cust Impact Offset		2,576	MWh	0.00	mills/kWh		$0
System Usage Charge		2,576	MWh	1.33	mills/kWh		$3
COS Energy Charge		2,576	MWh	50.98	mills/kWh		$131
Subtotal							$189
					w/o CIO		$189

Summary of Inputs	Allocated Inputs	DesSumm	Deltas
Functional Costs			
Basic Charge	$344,872	$344,872	($0)
Trans. & Rel. Serv. Charge	$92,225	$92,225	$0
Distribution Charge	$493,534	$493,534	$0
Fixed Charges	$7,195	$7,195	$0
Franchise Fees & Other	$39,910	$39,910	$0
Energy Charge	$1,062,497	$1,062,497	$0
Subtotal	$2,040,233	$2,040,233	

Functional Costs Revenues	Annual Revenue	Revenue	Deltas		
Basic Charge	$161,710	$161,710	$0		
Trans. & Rel. Serv. Charge	$92,237	$92,215	($22)	($22)	(Voluntary TOU)

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2022

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	o	Annual Revenue ($000)
Distribution Charges	$633,309	$633,331	$22	$22	(Voluntary TOU)		
Fixed Charges	$7,195	$7,195	$0				
System Usage Charge	$58,825	$58,825	$0				
Energy Charge	$1,085,643	$1,085,612	($31)	($31)	(Voluntary TOU)		
Reactive	$1,390	$1,390	$0				
Subtotal	$2,040,309	$2,040,278	($31)	($31)			$2,040,307

Note: figures are before employee discount and Schedule 129

On-peak demand	24,837,139	24,837,139	0
Facility Capacity	30,184,401	30,184,401	0
kVar	2,779,978	2,779,978	0

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at Current Prices ($000)	2022 Allocated Costs ($000)	Percent Change	Impact Offset Amount	Impact Offset MWH	CIO mills/kWh	CIO Revenues
Schedule 7	7,555,010	$1,018,312	$1,114,371	9.4%		7,555,010	(0.65)	($4,907)
Schedule 15	14,480	$3,231	$3,797	17.5%			(22.09)	($320)
Schedule 32	1,576,157	$194,110	$210,488	8.4%		1,576,157	(2.35)	($3,704)
Schedule 38	31,528	$4,332	$4,306	-0.6%			0.00	$0
Schedule 47	20,075	$4,170	$4,376	5.0%			0.00	$0
Schedule 49	61,430	$9,326	$10,021	7.5%			0.00	$0
Schedule 83	2,800,127	$272,881	$281,522	3.2%			0.00	$0
Schedule 85	2,746,945	$248,856.69	$238,896.65	-4.0%		2,746,945	1.64	$4,505
Schedule 89/75	616,608	$62,790.58	$52,944	-15.7%		616,608	1.37	$845
Schedule 90	2,824,250	$176,594	$170,052	-3.7%		2,824,250	0.00	$0
Schedules 91 & 95	41,836	$9,398	$10,472	11.4%			7.65	$320
Schedule 92	2,576	$226	$196	-13.4%			0.00	$0
COS TOTALS	18,291,022							
Sch 485 Energy	891,955						1.64	$1,463
Sch 489 Energy	1,265,391					1,265,391	1.37	$1,734
Sch 689 Energy	48,674						1.37	$67
Totals	20,497,042	$2,004,227	$2,101,441	4.9%	$0	16,584,361		$2

Note: does not include Sch 76R	$0	$0
Note: does not include employee discount	($1,134)	($1,235)
Reconcile CIO worksheet to revenues	$2,003,093	$2,100,206
	$2,006,036	$2,101,651
	(2,943)	(1,445)

Schedules	CIO Allocation	MWh	CIO (mills/kWh)
85/485/585	$5,950,000	3,638,900	1.64
89/489/589/689	$2,650,000	1,930,673	1.37
90/490/590	$0	2,824,250	0
Totals	$8,600,000	8,393,823	

PORTLAND GENERAL ELECTRIC
2022 Test Period Functionalized Revenue Requirement

Function	Amount	Spread
PRODUCTION	$1,063,469	$1,063,469
TRANSMISSION	$87,205	$87,205
ANCILLARY	$5,119	$5,119
DISTRIBUTION	$721,855	$721,855
METERING	$6,216	$6,216
BILLING	$37,795	$37,795
CONSUMER	$127,424	$127,424
TOTALS	$2,049,083	$2,049,083
Schedule 129		($8,180)
Scheduel 139		($257)
Employee Discount		$1,163
Partial Requirements Transmission		$0
Partial Requirements Distribution		$0
Spread Total		$2,041,810

Note: Employee discount is allocated to distribution

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2022 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$551,703	$551,199
Net Variable Power Costs	$511,766	$511,298
Production Costs	$1,063,469	$1,062,497
Ancillary Services	$5,119	$5,113
Transmission		
Transmission	$87,205	
Partial Requirements Daily Demand	$0	
Transmission Costs	$87,205	$87,112
Distribution Services	$721,855	
Franchise	($46,473)	
Uncollectibles	($5,977)	
Trojan Decommissioning	($1,900)	
Partial Requirements Daily Demand	$0	
Employee Discount	$1,163	$1,163
Distribution Costs	$668,668	$668,289
Consumer Services		
Metering Services	$6,216	$6,213
Billing Services	$37,795	$37,774
Other Consumer Services	$127,424	$127,352
Franchise Fees	$46,473	$46,447
Uncollectibles	$5,977	$5,973
Trojan Decommissioning	$1,900	$1,899
Schedule 129	($8,180)	($8,180)
Schedule 139	($257)	($257)
Totals	$2,041,810	$2,040,233
Net of employee discount	$2,040,647	$2,039,070
Net of Sch 129 and Sch 139	$2,049,083	$2,047,506
Calendar MWH (COS & ESS)	20,508,658	
Cycle MWH (COS & ESS)	20,497,042	
Cycle/Cal Ratio	99.94%	
COS Calendar Energy MWH	18,310,482	
COS Cycle MWH	18,291,022	
Cycle/Cal Ratio	99.89%	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF GENERATION REVENUE REQUIREMENT TO COS CUSTOMERS
2022

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)
Schedule 7	7,560,991	$289,178	52.55%	$162,867	$452,045	45.23%	$1,555	$482,597	$482,216
Schedule 15	14,480	$487	0.05%	$161	$647	0.06%	$2	$691	$691
Schedule 32	1,576,916	$59,781	8.03%	$24,878	$84,660	8.47%	$291	$90,382	$90,338
Schedule 38	31,529	$1,199	0.12%	$366	$1,565	0.16%	$5	$1,670	$1,670
Schedule 47	20,699	$834	0.13%	$403	$1,238	0.12%	$4	$1,321	$1,282
Schedule 49	61,728	$2,497	0.42%	$1,300	$3,796	0.38%	$13	$4,053	$4,033
Schedule 83	2,801,114	$106,862	13.68%	$42,395	$149,258	14.94%	$513	$159,345	$159,289
Schedule 85	2,730,198	$101,003	12.20%	$37,802	$138,805	13.89%	$1,372	$149,081	$149,995
Schedule 89/75	615,214	$22,343	2.26%	$7,019	$29,361	2.94%	$1,064	$32,309	$32,382
Schedule 90	2,853,201	$103,736	10.40%	$32,234	$135,969	13.61%	($4,828)	$139,864	$138,445
Schedule 91/95	41,836	$1,406	0.16%	$490	$1,896	0.19%	$7	$2,024	$2,024
Schedule 92	2,576	$95	0.01%	$29	$123	0.01%	$0	$131	$131
TOTAL	18,310,482	$689,421	100.0%	$309,942	$999,363	100.00%	($0)	$1,063,469	$1,062,497
Simple Cycle Proxy Plant $/kW				$87.50		**TARGET**		**$1,063,469**	
Projected Peak Load				3,542					
Marginal Capacity Costs ($000)				$309,942					

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	1,533.4	$55.93	$85,763	49.45%	$43,074
Schedule 15	1.5	$55.93	$83	0.05%	$42
Schedule 32	253.5	$55.93	$14,178	8.17%	$7,121
Schedule 38	4.5	$55.93	$251	0.14%	$126
Schedule 47	3.3	$55.93	$183	0.11%	$92
Schedule 49	10.1	$55.93	$565	0.33%	$284
Schedule 83	447.3	$55.93	$25,020	14.43%	$12,566
Schedule 85	408.3	$55.93	$22,837	13.17%	$11,470
Schedule 89	79.5	$55.93	$4,447	2.56%	$2,234
Schedule 90-P	354.8	$55.93	$19,845	11.44%	$9,967
Schedules 91/95	4.6	$55.93	$255	0.15%	$128
Schedule 92	0.3	$55.93	$17	0.01%	$9
Totals	3,101.1		$173,443		
Target				100.00%	$87,112
Unit Marginal Cost $/kW		**$55.93**			

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE REVENUE REQUIREMENT
2022

Schedules	Production Allocation Percent	Class Revenue Requirement
Schedule 7	45.23%	$2,313
Schedule 15	0.06%	$3
Schedule 32	8.47%	$433
Schedule 38	0.16%	$8
Schedule 47	0.12%	$6
Schedule 49	0.38%	$19
Schedule 83	14.94%	$764
Schedule 85	13.89%	$710
Schedule 89	2.94%	$150
Schedule 90-P	13.61%	$696
Schedules 91/95	0.19%	$10
Schedule 92	0.01%	$1
TOTAL	100.00%	$5,113
	TARGET	$5,113

PORTLAND GENERAL ELECTRIC

Applicable 2022 Ancillary Services Charges

Line	Ancillary Service	Billing Determinant	OATT Price	Total
	SCHEDULE 1 - SCHEDULING, SYSTEM CONTROL and DISPATCH		$/MW year	
1	12 CP MW Average	3,092	$149.89	$463,497
	SCHEDULE 2 - REACTIVE SUPPLY & VOLTAGE CONTROL		$/kW year	
2	12 CP kW Average	3,092,250	$0.461	$1,425,527
	SCHEDULE 3 - REGULATION & FREQUENCY RESPONSE		$/kW month	
3	Billing Determinant: Sum of Monthly Average 12 CP KW Charge: $6.695 per kW per month x .013	37,107,005	$0.09	$3,229,608
4			**ANCILLARY SERVICES TOTAL**	$5,118,633

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2022

Schedules	Cycle Generation Revenues	Allocation Percent	Class Revenue Requirement
Schedule 7	$505,422,462	42.03%	$798
Schedule 15	$690,986	0.06%	$1
Schedule 32	$90,392,588	7.52%	$143
Schedule 38	$1,670,457	0.14%	$3
Schedule 47	$1,281,590	0.11%	$2
Schedule 49	$4,033,513	0.34%	$6
Schedule 83	$159,289,321	13.25%	$252
Schedule 85-S	$145,155,425	12.07%	$229
Schedule 89-S	$741,394	0.06%	$1
Schedule 85-P	$53,006,325	4.41%	$84
Schedule 89-P	$84,736,600	7.05%	$134
Schedule 89-T	$15,455,757	1.29%	$24
Schedule 90-P	$138,440,638	11.51%	$219
Schedule 91/95	$2,024,444	0.17%	$3
Schedule 92	$131,325	0.01%	$0
TOTAL	$1,202,472,823		$1,899
		TARGET	$1,899

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2022

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	$539,982	$45,387	$482,216		$1,067,585	$12,474	$1,048	$11,139		$24,662
Schedule 15	$2,947	$45	$691		$3,684	$68	$1	$16		$85
Schedule 32	$104,072	$7,554	$90,338		$201,964	$2,404	$175	$2,087		$4,665
Schedule 38	$2,335	$134	$1,670		$4,140	$54	$3	$39		$96
Schedule 47	$2,843	$98	$1,282		$4,223	$66	$2	$30		$98
Schedule 49	$5,286	$303	$4,033		$9,623	$122	$7	$93		$222
Schedule 83	$95,900	$13,330	$159,289		$268,519	$2,215	$308	$3,680		$6,203
Schedule 85	$62,759	$12,180	$149,995	$3,878	$228,812	$1,450	$281	$3,465	$79	$5,275
Schedule 89	$11,143	$3,102	$32,382	$4,558	$51,186	$257	$72	$748	$116	$1,193
Schedule 90-P	$12,196	$9,945	$138,445		$160,586	$282	$230	$3,198		$3,710
Schedules 91/95	$7,991	$138	$2,024		$10,153	$185	$3	$47		$235
Schedule 92	$45	$9	$131		$186	$1	$0	$3		$4
TOTALS	$847,500	$92,225	$1,062,497	$8,436	$2,010,658	$19,578	$2,130	$24,544	$195	$46,447

Franchise Fee Revenue Requirement **$46,447**

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	7,555,010	1.65	7,555,010	0.14	7,555,010	1.47	0		3.26		
Schedule 15	14,480	4.70	14,480	0.07	14,480	1.10	0		5.88	4.70	1.17
Schedule 32	1,576,157	1.53	1,576,157	0.11	1,576,157	1.32	0		2.96	1.53	1.43
Schedule 38	31,528	1.71	31,528	0.10	31,528	1.22	0		3.03	1.71	1.32
Schedule 47	20,075	3.27	20,075	0.11	20,075	1.47	0		4.86		
Schedule 49	61,430	1.99	61,430	0.11	61,430	1.52	0		3.62	1.99	1.63
Schedule 83	2,800,127	0.79	2,800,127	0.11	2,800,127	1.31	0		2.22	0.79	1.42
Schedule 85-S	2,652,837	0.40	2,134,357	0.10	2,134,357	1.26	518,480	0.09	1.77	0.49	1.28
Schedule 89-S	13,878	0.14	0	0.12	0	1.23	13,878	0.09	1.48	0.22	1.26
Schedule 85-P	986,063	0.40	612,588	0.10	612,588	1.25	373,475	0.09	1.75	0.48	1.26
Schedule 89-P	1,619,259	0.13	562,911	0.12	562,911	1.21	1,056,348	0.09	1.46	0.22	1.24
Schedule 89-T/75-T	297,536	0.13	53,697	0.12	53,697	1.20	243,839	0.09	1.45	0.22	1.23
Schedule 90-P	2,824,250	0.10	2,824,250	0.08	2,824,250	1.13			1.31	0.10	1.21
Schedule 91/95	41,836	4.41	41,836	0.08	41,836	1.12	0		5.61	4.41	1.19
Schedule 92	2,576	0.40	2,576	0.08	2,576	1.18	0		1.67	0.40	1.26
TOTALS	20,497,042		18,291,022		18,291,022		2,206,020				

Revenues

Schedules	MWh	Fran. Fee mills/kWh	Fran. Fee Revenues
Schedule 7	7,555,010	3.26	$24,662
Schedule 15	14,480	5.88	$85
Schedule 32	1,576,157	2.96	$4,665
Schedule 38	31,528	3.03	$96
Schedule 47	20,075	4.86	$98
Schedule 49	61,430	3.62	$222
Schedule 83	2,800,127	2.22	$6,203
Schedule 85-S	2,134,357	1.77	$3,771
Schedule 485-S	518,480	0.49	$253
Schedule 89-S	0	1.48	$0
Schedule 489-S	13,878	0.22	$3
Schedule 85-P	612,588	1.75	$1,070
Schedule 485-P	373,475	0.48	$181
Schedule 89-P	562,911	1.46	$824
Schedule 489-P	1,056,348	0.22	$234
Schedule 89-T/75-T	53,697	1.45	$78
Schedule 489-T	243,839	0.22	$54
Schedule 90-P	2,824,250	1.31	$3,710
Schedule 91/95	41,836	5.61	$235
Schedule 92	2,576	1.67	$4
TOTALS	20,497,042		$46,447

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129/139 TRANSITION ADJUSTMENT
2022

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 85-S	2,652,837	31.6%	$0	0.00
Schedule 89-S	13,878	0.2%	$0	0.00
Schedule 85-P	986,063	11.7%	$0	0.00
Schedule 89-P	1,619,259	19.3%	$0	0.00
Schedule 90-P	2,824,250	33.6%	$0	0.00
Schedule 89-T/75-T	297,536	3.5%	$0	0.00
TOTAL	8,393,823	100.00%	$0	
		TARGET	$0	0.00

ALLOCATION OF TRANSITION ADJUSTMENT FOR POST 2017 VINTAGE CUSTOMERS

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 7	7,555,010	36.9%	($3,110)	(0.41)
Schedule 15	14,480	0.1%	($6)	(0.41)
Schedule 32	1,576,157	7.7%	($649)	(0.41)
Schedule 38	31,528	0.2%	($13)	(0.41)
Schedule 47	20,075	0.1%	($8)	(0.41)
Schedule 49	61,430	0.3%	($25)	(0.41)
Schedule 83	2,800,127	13.7%	($1,153)	(0.41)
Schedule 85-S	2,652,837	12.9%	($1,092)	(0.41)
Schedule 89-S	13,878	0.1%	($6)	(0.41)
Schedule 85-P	986,063	4.8%	($406)	(0.41)
Schedule 89	1,619,259	7.9%	($666)	(0.41)
Schedule 89-T/75-T	297,536	1.5%	($122)	(0.41)
Schedule 90-P	2,824,250	13.8%	($1,162)	(0.41)
Schedules 91/95	41,836	0.2%	($17)	(0.41)
Schedule 92	2,576	0.0%	($1)	(0.41)
TOTAL	20,497,042	100.00%	($8,436)	(0.41)
		TARGET	($8,436)	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF UNCOLLECTIBLES
2022

Grouping	Marginal Cost Allocation Percent	Class Revenue Requirement
Schedule 7		
Single Phase	83.36%	$4,979
Three Phase	0.00%	$0
Schedule 15		
Residential	0.07%	$4
Commercial	0.09%	$5
Schedule 32		
Single Phase	4.04%	$241
Three Phase	3.10%	$185
Schedule 38		
Single Phase	0.00%	$0
Three Phase	0.00%	$0
Schedule 47		
Single Phase	0.35%	$21
Three Phase	3.60%	$215
Schedule 49		
Single Phase	0.00%	$0
Three Phase	0.26%	$15
Schedule 83		
Single Phase	0.25%	$15
Three Phase	3.74%	$223
Schedule 85		
Secondary	0.80%	$48
Primary	0.12%	$7
Schedule 89		
Secondary	0.01%	$0
Primary	0.17%	$10
Subtransmission	0.05%	$3
Schedule 90-P	0.00%	$0
Schedules 91/95	0.00%	$0
Schedule 92	0.00%	$0
TOTAL	100.00%	$5,973
	TARGET	$5,973

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2022

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	809,036	Customers	$22.05	$17,839	$24,654
		Three-Phase Customers	0	Customers	$51.68	$0	$0
	Transformer & Service						
		Single-Phase Customers	809,036	Customers	$74.68	$60,419	$83,501
		Three-Phase Customers	0	Customers	$164.36	$0	$0
FACILITIES	Feeder Backbone						
		Single-Phase Customers	1,928,711	kW, rateclass peak	$29.14	$56,203	$77,674
		Three-Phase Customers	0	kW, rateclass peak	$29.14	$0	$0
	Feeder Local Facilities						
		Single-Phase Customers	3,236,145	Design Demand	$40.48	$130,999	$181,045
		Three-Phase Customers	0	Design Demand	$40.48	$0	$0
DEMAND	Subtransmission		1,966,513	kW, rateclass peak	$4.17	$8,200	$11,333
	Substation		1,928,711	kW, rateclass peak	$10.68	$20,599	$28,468
SUBTOTAL						$294,259	$406,676
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		6,736	Lights	$2.81	$19	$26
	Transformer & Service		6,736	Lights	$2.42	$16	$23
FACILITIES	Feeder Backbone		439	kW, rateclass peak	$30.41	$13	$18
	Feeder Local Facilities		439	Design Demand	$40.56	$18	$25
DEMAND	Subtransmission		448	kW, rateclass peak	$4.17	$2	$3
	Substation		439	kW, rateclass peak	$10.68	$5	$6
FIXED	Luminaires & Poles						$197
SUBTOTAL						$73	$298
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		14,474	Lights	$2.81	$41	$56
	Transformer & Service		14,474	Lights	$2.42	$35	$48
FACILITIES	Feeeder Backbone		3,276	kW, rateclass peak	$30.41	$100	$138
	Feeder Local Facilities		3,276	Design Demand	$40.56	$133	$184
DEMAND	Subtransmission		3,340	kW, rateclass peak	$4.17	$14	$19
	Substation		3,276	kW, rateclass peak	$10.68	$35	$48
FIXED	Luminaires & Poles						$1,469
SUBTOTAL						$357	$1,963
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$82
	Transformer & Service						$71
FACILITIES	Feeeder Backbone						$156
	Feeder Local Facilities						$208
DEMAND	Subtransmission						$22
	Substation						$55
FIXED	Luminaires & Poles						$1,666
SUBTOTAL							$2,260
Schedule 32 Small Non residential General Service							
CUSTOMER	Meters						
		Single-Phase Customers	53,573	Customers	$47.76	$2,559	$3,536
		Three-Phase Customers	41,076	Customers	$66.13	$2,716	$3,754
	Transformer & Service						
		Single-Phase Customers	53,573	Customers	$157.85	$8,457	$11,687
		Three-Phase Customers	41,076	Customers	$265.66	$10,912	$15,081
FACILITIES	Feeder Backbone						
		Single-Phase Customers	111,877	kW, rateclass peak	$35.13	$3,930	$5,432
		Three-Phase Customers	209,980	kW, rateclass peak	$35.13	$7,377	$10,195
	Feeder Local Facilities						
		Single-Phase Customers	241,080	Design Demand	$61.90	$14,923	$20,624
		Three-Phase Customers	447,726	Design Demand	$16.39	$7,338	$10,142
DEMAND	Subtransmission		328,165	kW, rateclass peak	$4.17	$1,368	$1,891
	Substation		321,857	kW, rateclass peak	$10.68	$3,437	$4,751
SUBTOTAL						$63,018	$87,092
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	51	Customers	$54.31	$3	$4
		Three-Phase Customers	326	Customers	$108.52	$35	$49
	Transformer & Service						
		Single-Phase Customers	51	Customers	$165.25	$8	$12
		Three-Phase Customers	326	Customers	$488.06	$159	$220
FACILITIES	Feeder Backbone						
		Single-Phase Customers	470	kW, rateclass peak	$36.04	$17	$23
		Three-Phase Customers	9,909	kW, rateclass peak	$36.04	$357	$494
	Feeder Local Facilities						
		Single-Phase Customers	2,454	Design Demand	$63.08	$155	$214
		Three-Phase Customers	37,588	Design Demand	$18.44	$693	$958
DEMAND	Subtransmission		10,582	kW, rateclass peak	$4.17	$44	$61
	Substation		10,379	kW, rateclass peak	$10.68	$111	$153
SUBTOTAL						$1,583	$2,187
Schedule 47 Irrigation & Drainage Service < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	245	Customers	$54.86	$13	$19
		Three-Phase Customers	2,530	Customers	$75.87	$192	$265
	Transformer & Service						
		Single-Phase Customers	245	Customers	$9.05	$2	$3
		Three-Phase Customers	2,530	Customers	$18.00	$46	$63
FACILITIES	Feeder Backbone						
		Single-Phase Customers	672	kW, rateclass peak	$35.13	$24	$33
		Three-Phase Customers	10,317	kW, rateclass peak	$35.13	$362	$501
	Feeder Local Facilities						
		Single-Phase Customers	2,548	Design Demand	$58.44	$149	$206
		Three-Phase Customers	39,721	Design Demand	$15.47	$614	$849
DEMAND	Subtransmission		11,204	kW, rateclass peak	$4.17	$47	$65
	Substation		10,989	kW, rateclass peak	$10.68	$117	$162
SUBTOTAL						$1,567	$2,165
Schedule 49 Irrigation & Drainage Service > 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	17	Customers	$54.86	$1	$1
		Three-Phase Customers	1,388	Customers	$65.99	$92	$127
	Transformer & Service						
		Single-Phase Customers	17	Customers	$121.75	$2	$3
		Three-Phase Customers	1,388	Customers	$121.75	$169	$234
FACILITIES	Feeder Backbone						
		Single-Phase Customers	434	kW, rateclass peak	$36.04	$16	$22
		Three-Phase Customers	35,439	kW, rateclass peak	$36.04	$1,277	$1,765
	Feeder Local Facilities						
		Single-Phase Customers	632	Design Demand	$60.92	$39	$53
		Three-Phase Customers	77,867	Design Demand	$17.81	$1,387	$1,917
DEMAND	Subtransmission		36,576	kW, rateclass peak	$4.17	$153	$211
	Substation		35,873	kW, rateclass peak	$10.68	$383	$529
SUBTOTAL						$3,517	$4,861
Schedule 83 General Service (31 200 kW)							
CUSTOMER	Meters						
		Single-Phase Customers	755	Customers	$54.86	$41	$57
		Three-Phase Customers	11,089	Customers	$114.60	$1,271	$1,756
	Transformer & Service						
		Single-Phase Customers	755	Customers	$364.47	$275	$381
		Three-Phase Customers	11,089	Customers	$974.14	$10,802	$14,929
FACILITIES	Feeder Backbone						
		Single-Phase Customers	23,857	kW, rateclass peak	$36.04	$860	$1,188
		Three-Phase Customers	567,233	kW, rateclass peak	$36.04	$20,443	$28,253
	Feeder Local Facilities						
		Single-Phase Customers	36,336	Design Demand	$63.08	$2,292	$3,168
		Three-Phase Customers	864,936	Design Demand	$18.44	$15,949	$22,043
DEMAND	Subtransmission		602,675	kW, rateclass peak	$4.17	$2,513	$3,473
	Substation		591,090	kW, rateclass peak	$10.68	$6,313	$8,725
SUBTOTAL						$60,760	$83,972
Schedule 85 General Service (201 4,000 kW)							
CUSTOMER	Meters						
		Secondary Customers	1,534	Customers	$123.23	$189	$261
		Primary Customers	234	Customers	$1,985.33	$464	$641
	Transformer & Service						
		Secondary Customers	1,534	Customers	$2,242.07	$3,438	$4,752
		Primary Customers	234	Customers	$0.00	$0	$0
FACILITIES	Feeder Backbone		642,666	kW, rateclass peak	$26.84	$17,249	$23,839
	Feeder Local Facilities		901,870	Design Demand	$6.72	$6,061	$8,376
DEMAND	Subtransmission		655,262	kW, rateclass peak	$4.17	$2,732	$3,776
	Substation		642,666	kW, rateclass peak	$10.68	$6,864	$9,486
SUBTOTAL						$36,997	$51,131
Schedule 89 General Service (4,000 plus kW)							
CUSTOMER	Meters						
		Secondary Meters	1	Customers	$123.23	$0	$0
		Primary Meters	27	Customers	$2,097.42	$57	$78
		Substation Meters	8	Customers	$19,844.95	$159	$219
	Transformer & Service						
		Secondary Customers	1	Customers	$17,117.73	$17	$24
		Primary Customers	27	Customers	$0.00	$0	$0
FACILITIES	Feeder Backbone						
		Secondary Customers	1	Customers	$70,405.00	$70	$97
		Primary Customers	27	Customers	$70,405.00	$1,901	$2,627
		Subtransmission 115 kV Feeder	8	Customers	$73,568.00	$589	$813
DEMAND	Subtransmission		305,095	kW, rateclass peak	$4.17	$1,272	$1,758
	Substation (Sec. & Prim. Only)		253,600	kW, rateclass peak	$10.68	$2,708	$3,743
SUBTOTAL						$6,773	$9,361
Schedule 90 Primary Voltage Service							
CUSTOMER	Meters						
		Primary Meters	6	Customers	$2,097.42	$13	$17
FACILITIES	Feeder Backbone						
		Primary Customers	6	Customers	$331,061.00	$1,986	$2,745
DEMAND	Subtransmission		389,468	kW, rateclass peak	$4.17	$1,624	$2,245
	Substation (Sec. & Prim. Only)		381,981	kW, rateclass peak	$10.68	$4,080	$5,638
SUBTOTAL						$7,703	$10,645
Schedules 91 & 95 Streetlighting & Highway Lighting							
CUSTOMER	Customer Service		147,419	Lights	$2.81	$414	$572
	Transformer & Service		147,419	Lights	$2.42	$357	$493
FACILITIES	Feeder Backbone		10,734	kW, rateclass peak	$30.41	$326	$451
	Feeder Local Facilities		10,734	Design Demand	$42.63	$458	$632
DEMAND	Subtransmission		10,944	kW, rateclass peak	$4.17	$46	$63
	Substation		10,734	kW, rateclass peak	$10.68	$115	$158
FIXED	Luminaires & Poles						$5,529
SUBTOTAL						$1,715	$7,899
Schedule 92 Traffic Signals							
CUSTOMER	Transformer & Service		1,248	Intersections	$7.72	$10	$13
FACILITIES	Feeder Backbone		301	kW, rateclass peak	$30.41	$9	$13
	Feeder Local Facilities		301	Design Demand	$15.12	$5	$6
DEMAND	Subtransmission		306	kW, rateclass peak	$4.17	$1	$2
	Substation		301	kW, rateclass peak	$10.68	$3	$4
SUBTOTAL						$28	$38
Summary							
CUSTOMER	Meters		921,896	Customers		$25,644	$35,440
	Transformer & Service			Customers		$95,125	$131,465
	Customer Service		168,629	Lights		$473	$654
FACILITIES	Feeder Backbone		3,556,315	kW, rateclass peak		$113,109	$156,321
	Feeder Local Facilities		5,903,653	Design Demand		$181,212	$250,441
DEMAND	Subtransmission		4,320,578	kW, rateclass peak		$18,017	$24,900
	Substation		4,191,896	kW rateclass peak		$44,789	$61,873
FIXED	Luminaires & Poles						$7,195
TOTALS						$478,349	$668,289
						TARGET	$668,289
					EQUAL PERCENT		139.20%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2022

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	809,036	$0.21	$170	$4,147
Three Phase	0	$0.21	$0	$0
Schedule 15				
Residential	4,008	$0.00	$0	$0
Commercial	4,961	$0.00	$0	$0
Schedule 32				
Single Phase	53,573	$0.53	$28	$693
Three Phase	41,076	$0.53	$22	$531
Schedule 38				
Single Phase	51	$3.67	$0	$5
Three Phase	326	$3.67	$1	$29
Schedule 47				
Single Phase	245	$0.53	$0	$3
Three Phase	2,530	$0.53	$1	$33
Schedule 49				
Single Phase	17	$0.96	$0	$0
Three Phase	1,388	$0.96	$1	$33
Schedule 83				
Single Phase	755	$2.00	$2	$37
Three Phase	11,089	$2.00	$22	$541
Schedule 85				
Secondary	1,534	$3.70	$6	$139
Primary	234	$3.70	$1	$21
Schedule 89				
Secondary	1	$0.14	$0	$0
Primary	27	$0.14	$0	$0
Subtransmission	8	$0.14	$0	$0
Schedule 90-P	6	$0.14	$0	$0
Schedules 91/95	184	$0.00	$0	$0
Schedule 92	16	$0.00	$0	$0
TOTAL	931,065		$254	$6,213
			TARGET	$6,213
		EQUAL PERCENT		2441%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2022

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	809,036	$24.60	$19,902	$31,215
Three Phase	0	$24.60	$0	$0
Schedule 15				
Residential	4,008	$14.61	$59	$92
Commercial	4,961	$12.01	$60	$93
Schedule 32				
Single Phase	53,573	$24.77	$1,327	$2,081
Three Phase	41,076	$24.77	$1,017	$1,596
Schedule 38				
Single Phase	51	$97.43	$5	$8
Three Phase	326	$97.43	$32	$50
Schedule 47				
Single Phase	245	$23.46	$6	$9
Three Phase	2,530	$23.46	$59	$93
Schedule 49				
Single Phase	17	$97.71	$2	$3
Three Phase	1,388	$97.71	$136	$213
Schedule 83				
Single Phase	755	$104.39	$79	$124
Three Phase	11,089	$104.39	$1,158	$1,816
Schedule 85				
Secondary	1,534	$105.18	$161	$253
Primary	234	$105.18	$25	$39
Schedule 89				
Secondary	1	$88.42	$0	$0
Primary	27	$88.42	$2	$4
Subtransmission	8	$88.42	$1	$1
Schedule 90-P	6	$94.23	$1	$1
Schedules 91/95	184	$273.82	$50	$79
Schedule 92	16	$214.48	$3	$5
TOTAL	931,065		$24,084	$37,774
			TARGET	$37,774
		EQUAL PERCENT		157%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2022

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	809,036	$19.61	$15,865	$92,167
Three Phase	0	$19.61	$0	$0
Schedule 15				
Residential	4,008	$9.43	$38	$220
Commercial	4,961	$9.43	$47	$272
Schedule 32				
Single Phase	53,573	$20.93	$1,121	$6,514
Three Phase	41,076	$20.93	$860	$4,994
Schedule 38				
Single Phase	51	$24.59	$1	$7
Three Phase	326	$24.59	$8	$47
Schedule 47				
Single Phase	245	$18.75	$5	$27
Three Phase	2,530	$18.75	$47	$276
Schedule 49				
Single Phase	17	$18.96	$0	$2
Three Phase	1,388	$18.96	$26	$153
Schedule 83				
Single Phase	755	$129.63	$98	$569
Three Phase	11,089	$129.63	$1,437	$8,351
Schedule 85				
Secondary	1,534	$1,052.74	$1,614	$9,379
Primary	234	$1,052.74	$246	$1,430
Schedule 89				
Secondary	1	$6,918.81	$7	$40
Primary	27	$6,918.81	$187	$1,085
Subtransmission	8	$6,918.81	$55	$322
Schedule 90-P	6	$42,702.19	$256	$1,488
Schedule 91/95	184	$9.43	$2	$10
Schedule 92	16	$9.43	$0	$1
TOTAL	931,065		$21,922	$127,352
			TARGET	$127,352
		EQUAL PERCENT		581%

Portland General Electric
Residential Basic Charge Calculation
2022 Year Residential Marginal Unit Costs
December 2022 Dollars per Customer per Year

	All Residential	Single Family	Multi-Family
No. Customer	809,036	540,004	269,032
Feeder Mainline ($/kw)	29.14	31.05	18.39
Feeder Tapline	36.19	43.99	20.18
Secondary Tapline	4.29	5.21	2.44
Transformer and Service	74.68	76.13	54.87
Meters	22.05	22.05	22.05
meter reading	$ 0.21	$ 0.21	$ 0.21
Billing & Collections	$ 24.60	$ 24.60	$ 24.60
Customer Service /Other	$ 19.61	$ 19.61	$ 19.61
Total Per Year	210.77	222.85	162.35
Total Per Monthly	17.56	18.57	13.53
Mulit-Family to Single-Family Differential			27%
Current Basic Charge	$11.00		
14% Movement Towards Cost		11.00	
27% Applied to Multi-Family			8.01
Proposed Basic Charge		12.5	8
Revenue Impact to Single-Family		9,720,075	
Revenue Impact to Multi-Family			(9,685,152)
Total Revenue Impact	34,923		

PORTLAND GENERAL ELECTRIC

PROPOSED
Summary of Area and Streetlighting Revenue

Schedule 15 - Area Lighting	
Fixtures & Maintenance	$1,041,648
Poles	$625,115
Energy (volumetric c/kWh rate)	$1,899,593
Total	**$3,566,356**

Schedule 91/95 - Street and Highway Lighting	
Fixtures & Maintenance (Options A&B)	$4,356,984
Poles (Options A&B)	$2,630,257
Energy (volumetric c/kWh rate)	$5,714,964
Total	**$12,702,206**

PORTLAND GENERAL ELECTRIC

Schedules 91 & 95, Proposed Prices, Counts an

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
79	Cobrahead - PD	HPS	70-watt	30	Standard	$0.00	$0.81	$3.70	$0.00	$2.93	$2.12	
84	Cobrahead - PD	HPS	100-watt	43	Standard	$0.00	$0.93	$5.31	$0.00	$3.96	$3.03	
85	Cobrahead - PD	HPS	150-watt	62	Standard	$0.00	$0.81	$7.65	$0.00	$5.18	$4.37	
89	Cobrahead - PD	HPS	200-watt	79	Standard	$0.00	$0.97	$9.75	$0.00	$6.54	$5.57	
86	Cobrahead - PD	HPS	250-watt	102	Standard	$0.00	$0.81	$12.58	$0.00	$8.00	$7.19	
87	Cobrahead - PD	HPS	400-watt	163	Standard	$0.00	$0.99	$20.11	$0.00	$12.48	$11.49	
33	Cobrahead	HPS	70-watt	30	Standard	$4.71	$1.10	$3.70	$6.83	$3.22	$2.12	
34	Cobrahead	HPS	100-watt	43	Standard	$4.41	$1.05	$5.31	$7.44	$4.08	$3.03	
35	Cobrahead	HPS	150-watt	62	Standard	$4.47	$1.06	$7.65	$8.84	$5.43	$4.37	
39	Cobrahead	HPS	200-watt	79	Standard	$5.11	$1.13	$9.75	$10.68	$6.70	$5.57	
36	Cobrahead	HPS	250-watt	102	Standard	$4.72	$1.07	$12.58	$11.91	$8.26	$7.19	
37	Cobrahead	HPS	400-watt	163	Standard	$4.91	$1.10	$20.11	$16.40	$12.59	$11.49	
31	Flood	HPS	250-watt	102	Standard	$6.03	$1.27	$12.58	$13.22	$8.46	$7.19	
32	Flood	HPS	400-watt	163	Standard	$6.03	$1.27	$20.11	$17.52	$12.76	$11.49	
40	Post-Top	HPS	100-watt	43	Standard	$5.30	$1.20	$5.31	$8.33	$4.23	$3.03	
76	Shoebox	HPS	70-watt	30	Standard	$4.97	$1.15	$3.70	$7.09	$3.27	$2.12	
77	Shoebox	HPS	100-watt	43	Standard	$0.00	$1.22	$5.31	$0.00	$4.25	$3.03	
78	Shoebox	HPS	150-watt	62	Standard	$0.00	$1.28	$7.65	$0.00	$5.65	$4.37	
81	Special Acorn	HPS	100-watt	43	Custom	$8.46	$1.67	$5.31	$11.49	$4.70	$3.03	
82	Victorian	HPS	150-watt	62	Custom	$8.46	$1.67	$7.65	$12.83	$6.04	$4.37	
49	Victorian	HPS	200-watt	79	Custom	$8.78	$1.72	$9.75	$14.35	$7.29	$5.57	
83	Victorian	HPS	250-watt	102	Custom	$8.69	$1.70	$12.58	$15.88	$8.89	$7.19	
64	Capitol Acorn	HPS	100-watt	43	Custom	$12.17	$2.23	$5.31	$15.20	$5.26	$3.03	
67	Capitol Acorn	HPS	150-watt	62	Custom	$0.00	$2.19	$7.65	$0.00	$6.56	$4.37	
65	Capitol Acorn	HPS	200-watt	79	Custom	$0.00	$2.27	$9.75	$0.00	$7.84	$5.57	
66	Capitol Acorn	HPS	250-watt	102	Custom	$0.00	$0.89	$12.58	$0.00	$8.08	$7.19	
12	Acorn - Indep.	HPS	100-watt	43	Custom	$9.56	$1.81	$5.31	$12.59	$4.84	$3.03	
13	Acorn - Indep.	HPS	150-watt	62	Custom	$0.00	$1.53	$7.65	$0.00	$5.90	$4.37	
98	Techtra	HPS	100-watt	43	Custom	$16.25	$2.84	$5.31	$19.28	$5.87	$3.03	
99	Techtra	HPS	150-watt	62	Custom	$17.01	$2.96	$7.65	$21.38	$7.33	$4.37	
88	Techtra	HPS	250-watt	102	Custom	$0.00	$2.73	$12.58	$0.00	$9.92	$7.19	
90	Westbrooke Acorn	HPS	70-watt	30	Custom	$11.53	$2.11	$3.70	$13.65	$4.23	$0.00	
91	Westbrooke Acorn	HPS	100-watt	43	Custom	$11.67	$2.13	$5.31	$14.70	$5.16	$3.03	
92	Westbrooke Acorn	HPS	150-watt	62	Custom	$0.00	$2.42	$7.65	$0.00	$6.79	$4.37	
93	Westbrooke Acorn	HPS	200-watt	79	Custom	$0.00	$0.95	$9.75	$0.00	$6.52	$5.57	
94	Westbrooke Acorn	HPS	250-watt	102	Custom	$10.24	$1.91	$12.58	$17.43	$9.10	$7.19	
62	Cobrahead	MH	150-watt	60	Custom	$0.00	$1.16	$7.40	$0.00	$5.39	$4.23	
61	Flood	MH	350-watt	139	Custom	$0.00	$1.45	$17.15	$0.00	$11.25	$9.80	
47	Flood	HPS	750-watt	285	Custom	$8.48	$1.78	$35.16	$28.58	$21.88	$20.10	
9	Mongoose	HPS	150-watt	62	Custom	$0.00	$1.98	$7.65	$0.00	$6.35	$4.37	
10	Mongoose	HPS	250-watt	102	Custom	$0.00	$1.99	$12.58	$0.00	$9.18	$0.00	
18	Ornamental Acorn Twin / Opt C	QL	85-watt	64	Custom	$0.00	$0.00	$7.90	$0.00	$0.00	$4.51	
20	Ornamental Acorn / Opt C	QL	55-watt	21	Custom	$0.00	$0.00	$2.59	$0.00	$0.00	$1.48	
26	Ornamental Acorn Twin / Opt C	QL	55-watt	42	Custom	$0.00	$0.00	$5.18	$0.00	$0.00	$2.96	
44	Composite Twin / Opt C	Comp	140-watt	54	Custom	$0.00	$0.00	$6.66	$0.00	$0.00	$3.81	
45	Composite Twin / Opt C	Comp	175-watt	66	Custom	$0.00	$0.00	$8.14	$0.00	$0.00	$4.65	
19	Cobrahead - (C) Only	MV	100-watt	39	Obsolete	$0.00	$0.00	$4.81	$0.00	$0.00	$2.75	
21	Cobrahead	MV	175-watt	66	Obsolete	$4.42	$1.06	$8.14	$9.07	$5.71	$4.65	
22	Cobrahead	MV	250-watt	94	Obsolete	$0.00	$0.00	$11.60	$0.00	$0.00	$6.63	
23	Cobrahead	MV	400-watt	147	Obsolete	$5.08	$1.10	$18.14	$15.44	$11.46	$10.36	
24	Cobrahead	MV	1,000-watt	374	Obsolete	$5.03	$1.22	$46.14	$31.40	$27.59	$26.37	
50	Special Box - Space-Glo	HPS	70-watt	30	Obsolete	$5.36	$0.00	$3.70	$7.48	$0.00	$0.00	
46	Special Box - Space-Glo	MV	175-watt	66	Obsolete	$5.36	$1.16	$8.14	$10.01	$5.81	$4.65	
51	Box - Gardco Hub / Opt C	HPS	Twin 70-watt	60	Obsolete	$0.00	$0.00	$7.40	$0.00	$0.00	$4.23	
52	Box - Gardco Hub / Opt C	HPS	70-watt	30	Obsolete	$0.00	$0.00	$3.70	$0.00	$0.00	$2.12	
53	Box - Gardco Hub	HPS	100-watt	43	Obsolete	$0.00	$1.49	$5.31	$0.00	$4.52	$3.03	
54	Box - Gardco Hub	HPS	150-watt	62	Obsolete	$0.00	$0.89	$7.65	$0.00	$5.26	$4.37	
55	Box - Gardco Hub / Opt C	HPS	250-watt	102	Obsolete	$0.00	$0.00	$12.58	$0.00	$0.00	$7.19	
56	Box - Gardco Hub / Opt C	HPS	400-watt	163	Obsolete	$0.00	$0.00	$20.11	$0.00	$0.00	$11.49	
58	Box - Gardco Hub	MH	250-watt	99	Obsolete	$0.00	$0.90	$12.21	$0.00	$7.88	$6.98	
59	Box - Gardco Hub	MH	400-watt	156	Obsolete	$0.00	$0.90	$19.25	$0.00	$11.90	$0.00	
48	Cobrahead	MH	175-watt	71	Obsolete	$0.00	$1.17	$8.76	$0.00	$6.18	$5.01	
60	Flood	MH	400-watt	156	Obsolete	$5.34	$1.20	$19.25	$16.34	$12.20	$11.00	
69	Cobrahead DW 70/100	HPS	100-watt	43	Obsolete	$0.00	$0.89	$5.31	$0.00	$3.92	$0.00	
70	Cobrahead DW 100/150	HPS	100-watt	43	Obsolete	$0.00	$0.89	$5.31	$0.00	$3.92	$0.00	
71	Cobrahead DW 100/150	HPS	150-watt	62	Obsolete	$0.00	$0.89	$7.65	$0.00	$5.26	$4.37	

PORTLAND GENERAL ELECTRIC

Schedules 91 & 95, Proposed Prices, Counts an

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
2	Victorian	QL	85-watt	32	Obsolete	$0.00	$0.33	$3.95	$0.00	$2.59	$2.26	
1	Victorian	QL	165-watt	60	Obsolete	$0.00	$0.97	$1.85	$0.00	$2.03	$1.06	
3	Techtra	QL	165-watt	60	Obsolete	$0.00	$1.28	$7.40	$0.00	$5.51	$4.23	
95	KIM SBC Shoebox	HPS	150-watt	62	Obsolete	$0.00	$0.89	$7.65	$0.00	$5.26	$4.37	
96	KIM Archetype	HPS	250-watt	102	Obsolete	$0.00	$2.01	$12.58	$0.00	$9.20	$7.19	
97	KIM Archetype	HPS	400-watt	163	Obsolete	$0.00	$2.45	$20.11	$0.00	$13.94	$11.49	
80	Acorn Type	HPS	70-watt	30	Obsolete	$8.36	$1.57	$3.70	$10.48	$3.69	$0.00	
73	GardCo Bronze - (C) Only	HPS	70-watt	30	Obsolete	$0.00	$0.00	$3.70	$0.00	$0.00	$2.12	
72	GardCo Bronze - (C) Only	MV	175-watt	66	Obsolete	$0.00	$0.00	$8.14	$0.00	$0.00	$4.65	
74	Acrylic Sphere - (C) Only	MV	400-watt	0	Obsolete	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
25	Post-Top - Black	HPS	70-watt	30	Obsolete	$5.14	$1.04	$3.70	$7.26	$3.16	$2.12	
43	Rect.Type - (C) Only	HPS	200-watt	79	Obsolete	$0.00	$0.00	$9.75	$0.00	$0.00	$5.57	
5	Incand. - (C) Only	IND	92-watt	31	Obsolete	$0.00	$0.00	$3.82	$0.00	$0.00	$2.19	
6	Incand. - (C) Only	IND	182-watt	62	Obsolete	$0.00	$0.00	$7.65	$0.00	$0.00	$4.37	
29	Town and Country Post-Top	MV	175-watt	66	Obsolete	$5.20	$1.10	$8.14	$9.85	$5.75	$4.65	
27	Flood	HPS	70-watt	30	Obsolete	$4.45	$1.09	$3.70	$6.57	$3.21	$0.00	
30	Flood	HPS	100-watt	43	Obsolete	$4.46	$1.07	$5.31	$7.49	$4.10	$3.03	
38	Flood	HPS	200-watt	79	Obsolete	$5.92	$1.16	$9.75	$11.49	$6.73	$5.57	
41	Cobrahead - PD	HPS	310-watt	124	Obsolete	$0.00	$1.27	$15.30	$0.00	$10.01	$8.74	
14	Ornamental - (C) Only	HPS	100-watt	43	Obsolete	$0.00	$0.00	$5.31	$0.00	$0.00	$3.03	
15	Twin Ornamental -(C) Only	HPS	Twin 100-watt	86	Obsolete	$0.00	$0.00	$10.61	$0.00	$0.00	$6.06	
7	Flourescent - (C) Only	FLR	28-watt	12	Obsolete	$0.00	$0.00	$1.48	$0.00	$0.00	$0.85	
100	Cobrahead	LED	>30W-35W	11	Standard	$4.75	$0.41	$1.36	$5.53	$1.19	$0.00	
101	Cobrahead	LED	>45W-50W	16	Standard	$4.72	$0.41	$1.97	$5.85	$1.54	$0.00	
102	Cobrahead	LED	>50W-55W	18	Standard	$4.96	$0.42	$2.22	$6.23	$1.69	$0.00	
103	Cobrahead	LED	>65W-70W	23	Standard	$5.16	$0.42	$2.84	$6.78	$2.04	$0.00	
104	Cobrahead	LED	>100W-110W	36	Standard	$5.53	$0.43	$4.44	$8.07	$2.97	$0.00	
105	Cobrahead	LED	>130W-140W	46	Standard	$6.09	$0.45	$5.68	$9.33	$3.69	$0.00	
107	Cobrahead	LED	>170W-180W	60	Standard	$6.88	$0.47	$7.40	$11.11	$4.70	$0.00	
108	Cobrahead	LED	>190W-200W	67	Standard	$7.18	$0.48	$8.27	$11.90	$5.20	$0.00	
109	Cobrahead	LED	>20W-25W	8	Standard	$9.57	$0.41	$0.99	$10.13	$0.97	$0.00	
132	Cobrahead	LED	>150W-160W	53	Standard	$6.99	$0.48	$6.54	$10.73	$4.22	$0.00	
133	Cobrahead	LED	>25W-30W	9	Standard	$4.49	$0.41	$1.11	$5.12	$1.04	$0.00	
134	Cobrahead	LED	>40W-45W	15	Standard	$4.62	$0.41	$1.85	$5.68	$1.47	$0.00	
135	Cobrahead	LED	>85W-90W	30	Standard	$5.21	$0.43	$3.70	$7.33	$2.55	$0.00	
200	Cobrahead	LED	>35W-40W	13	Standard	$4.50	$0.41	$1.60	$5.42	$1.33	$0.00	
201	Cobrahead	LED	>55W-60W	20	Standard	$4.63	$0.41	$2.47	$6.04	$1.82	$0.00	
202	Cobrahead	LED	>60W-65W	21	Standard	$4.64	$0.41	$2.59	$6.12	$1.89	$0.00	
203	Cobrahead	LED	>70W-75W	25	Standard	$5.23	$0.43	$3.08	$6.99	$2.19	$0.00	
204	Cobrahead	LED	>75W-80W	26	Standard	$5.24	$0.43	$3.21	$7.07	$2.26	$0.00	
205	Cobrahead	LED	>80W-85W	28	Standard	$5.25	$0.43	$3.45	$7.22	$2.40	$0.00	
206	Cobrahead	LED	>90W-95W	32	Standard	$5.25	$0.43	$3.95	$7.51	$2.69	$0.00	
207	Cobrahead	LED	>95W-100W	33	Standard	$5.25	$0.43	$4.07	$7.58	$2.76	$0.00	
208	Cobrahead	LED	>110W-120W	39	Standard	$5.26	$0.43	$4.81	$8.01	$3.18	$0.00	
209	Cobrahead	LED	>120W-130W	43	Standard	$5.27	$0.43	$5.31	$8.30	$3.46	$0.00	
210	Cobrahead	LED	>140W-150W	50	Standard	$7.06	$0.48	$6.17	$10.59	$4.01	$0.00	
211	Cobrahead	LED	>160W-170W	56	Standard	$7.06	$0.48	$6.91	$11.01	$4.43	$0.00	
212	Cobrahead	LED	>180W-190W	63	Standard	$7.07	$0.48	$7.77	$11.51	$4.92	$0.00	
110	Acorn	LED	>45W-50W	16	Custom	$9.71	$0.55	$1.97	$10.84	$1.68	$0.00	
111	Acorn	LED	>65W-70W	23	Custom	$11.67	$0.61	$2.84	$13.29	$2.23	$0.00	
137	Acorn	LED	>35W-40W	13	Custom	$11.70	$0.61	$1.60	$12.62	$1.53	$0.00	
138	Acorn	LED	>55W-60W	20	Custom	$11.70	$0.61	$2.47	$13.11	$2.02	$0.00	
139	Acorn	LED	>70W-75W	25	Custom	$11.70	$0.61	$3.08	$13.46	$2.37	$0.00	
213	Acorn	LED	>40W-45W	15	Custom	$11.79	$0.61	$1.85	$12.85	$1.67	$0.00	
214	Acorn	LED	>50W-55W	18	Custom	$11.80	$0.61	$2.22	$13.07	$1.88	$0.00	
215	Acorn	LED	>60W-65W	21	Custom	$11.81	$0.61	$2.59	$13.29	$2.09	$0.00	
112	Pendant (non-flared)	LED	53	18	Custom	$13.81	$0.67	$2.22	$15.08	$1.94	$0.00	
113	Pendant (non-flared)	LED	69	24	Custom	$13.92	$0.67	$2.96	$15.61	$2.36	$0.00	
114	Pendant (non-flared)	LED	85	29	Custom	$14.45	$0.69	$3.58	$16.49	$2.73	$0.00	
117	Pendant (flared)	LED	>50W-55W	18	Custom	$14.27	$0.68	$2.22	$15.54	$1.95	$0.00	
118	Pendant (flared)	LED	>65W-70W	23	Custom	$14.99	$0.70	$2.84	$16.61	$2.32	$0.00	
119	Pendant (flared)	LED	>80W-85W	28	Custom	$15.17	$0.71	$3.45	$17.14	$2.68	$0.00	
127	Pendant (non-flare)	LED	36	12	Custom	$13.08	$0.65	$1.48	$13.93	$1.50	$0.00	
128	Pendant (flare)	LED	>35W-40W	13	Custom	$13.24	$0.65	$1.60	$14.16	$1.57	$0.00	
216	Pendant (flare)	LED	>40W-45W	15	Standard	$13.35	$0.65	$1.85	$14.41	$1.71	$0.00	
217	Pendant (flare)	LED	>45W-50W	16	Standard	$13.35	$0.65	$1.97	$14.48	$1.78	$0.00	

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts an

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
218	Pendant (flare)	LED	>55W-60W	20	Standard	$14.40	$0.68	$2.47	$15.81	$2.09	$0.00	
219	Pendant (flare)	LED	>60W-65W	21	Standard	$14.40	$0.68	$2.59	$15.88	$2.16	$0.00	
220	Pendant (flare)	LED	>70W-75W	25	Standard	$15.13	$0.70	$3.08	$16.89	$2.46	$0.00	
221	Pendant (flare)	LED	>75W-80W	26	Standard	$15.32	$0.71	$3.21	$17.15	$2.54	$0.00	
129	Post-Top, American Revolution	LED	>30W-35W	11	Custom	$6.17	$0.45	$1.36	$6.95	$1.23	$0.00	
130	Post-Top, American Revolution	LED	>45W-50W	16	Custom	$6.49	$0.46	$1.97	$7.62	$1.59	$0.00	
131	HADCO Acorn	LED	70	24	Custom	$15.58	$0.72	$2.96	$17.27	$2.41	$0.00	
141	Flood	LED	>120W-130W	43	Standard	$6.69	$0.47	$5.31	$9.72	$3.50	$0.00	
142	Flood	LED	>180W-190W	63	Standard	$7.69	$0.50	$7.77	$12.13	$4.94	$0.00	
143	Flood	LED	>370W-380W	127	Standard	$11.86	$0.61	$15.67	$20.81	$9.56	$0.00	
144	Flood	LED	>80W-85W	28	Standard	$6.19	$0.45	$3.45	$8.16	$2.42	$0.00	
148	20 - 25	LED		8		$0.00	$0.00	$0.99	$0.00	$0.00	$0.56	
149	>25 - 30	LED		9		$0.00	$0.00	$1.11	$0.00	$0.00	$0.63	
150	>30 - 35	LED		11		$0.00	$0.00	$1.36	$0.00	$0.00	$0.78	
151	>35 - 40	LED		13		$0.00	$0.00	$1.60	$0.00	$0.00	$0.92	
152	>40 - 45	LED		15		$0.00	$0.00	$1.85	$0.00	$0.00	$1.06	
153	>45 - 50	LED		16		$0.00	$0.00	$1.97	$0.00	$0.00	$1.13	
154	>50 - 55	LED		18		$0.00	$0.00	$2.22	$0.00	$0.00	$1.27	
155	>55 - 60	LED		20		$0.00	$0.00	$2.47	$0.00	$0.00	$1.41	
156	>60 - 65	LED		21		$0.00	$0.00	$2.59	$0.00	$0.00	$1.48	
157	>65 - 70	LED		23		$0.00	$0.00	$2.84	$0.00	$0.00	$1.62	
158	>70 - 75	LED		25		$0.00	$0.00	$3.08	$0.00	$0.00	$1.76	
159	>75 - 80	LED		26		$0.00	$0.00	$3.21	$0.00	$0.00	$1.83	
160	>80 - 85	LED		28		$0.00	$0.00	$3.45	$0.00	$0.00	$1.97	
161	>85 - 90	LED		30		$0.00	$0.00	$3.70	$0.00	$0.00	$2.12	
162	>90 - 95	LED		32		$0.00	$0.00	$3.95	$0.00	$0.00	$2.26	
163	>95 - 100	LED		33		$0.00	$0.00	$4.07	$0.00	$0.00	$2.33	
164	>100 - 110	LED		36		$0.00	$0.00	$4.44	$0.00	$0.00	$2.54	
165	>110 - 120	LED		39		$0.00	$0.00	$4.81	$0.00	$0.00	$2.75	
166	>120 - 130	LED		43		$0.00	$0.00	$5.31	$0.00	$0.00	$3.03	
167	>130 - 140	LED		46		$0.00	$0.00	$5.68	$0.00	$0.00	$3.24	
168	>140 - 150	LED		50		$0.00	$0.00	$6.17	$0.00	$0.00	$3.53	
169	>150 - 160	LED		53		$0.00	$0.00	$6.54	$0.00	$0.00	$3.74	
170	>160 - 170	LED		56		$0.00	$0.00	$6.91	$0.00	$0.00	$3.95	
171	>170 - 180	LED		60		$0.00	$0.00	$7.40	$0.00	$0.00	$4.23	
172	>180 - 190	LED		63		$0.00	$0.00	$7.77	$0.00	$0.00	$4.44	
173	>190 - 200	LED		67		$0.00	$0.00	$8.27	$0.00	$0.00	$4.72	
174	>200 - 210	LED		70		$0.00	$0.00	$8.64	$0.00	$0.00	$4.94	
175	>210 - 220	LED		0		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
176	>220 - 230	LED		80		$0.00	$0.00	$9.87	$0.00	$0.00	$5.64	
177	>230 - 240	LED		0		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
178	>240 - 250	LED		84		$0.00	$0.00	$10.36	$0.00	$0.00	$5.92	
179	>250 - 260	LED		87		$0.00	$0.00	$10.73	$0.00	$0.00	$6.13	
180	>260 - 270	LED		0		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
181	>270 - 280	LED		94		$0.00	$0.00	$11.60	$0.00	$0.00	$6.63	
182	>280 - 290	LED		0		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
183	>290 - 300	LED		0		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	

Totals

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

d Revenue

Proposed Sch 91 & 95 A & B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	B	Annual Energy
-	-	-	0	30	$0	$0	$0
-	4	9	13	43	$0	$45	$828
-	-	47	47	62	$0	$0	$4,315
-	2	1	3	79	$0	$23	$351
-	-	2	2	102	$0	$0	$302
-	1	1	2	163	$0	$12	$483
5	42	312	359	30	$283	$554	$15,940
223	752	160	1,135	43	$11,801	$9,475	$72,322
10	290	194	494	62	$536	$3,689	$45,349
55	1,245	317	1,617	79	$3,373	$16,882	$189,189
24	717	384	1,125	102	$1,359	$9,206	$169,830
257	124	201	582	163	$15,142	$1,637	$140,448
88	1	3	92	102	$6,368	$15	$13,888
218	8	21	247	163	$15,774	$122	$59,606
1,161	2,356	354	3,871	43	$73,840	$33,926	$246,660
1	66	15	82	30	$60	$911	$3,641
-	802	1,788	2,590	43	$0	$11,741	$165,035
-	74	180	254	62	$0	$1,137	$23,317
157	2,080	245	2,482	43	$15,939	$41,683	$158,153
38	933	212	1,183	62	$3,858	$18,697	$108,599
3	97	3	103	79	$316	$2,002	$12,051
68	740	96	904	102	$7,091	$15,096	$136,468
4	20	7	31	43	$584	$535	$1,975
-	380	28	408	62	$0	$9,986	$37,454
-	61	-	61	79	$0	$1,662	$7,137
-	-	-	0	102	$0	$0	$0
47	3	22	72	43	$5,392	$65	$4,588
-	1	8	9	62	$0	$18	$826
509	38	-	547	43	$99,255	$1,295	$34,855
16	176	4	196	62	$3,266	$6,252	$17,993
-	60	-	60	102	$0	$1,966	$9,058
1	45	-	46	30	$138	$1,139	$2,042
31	423	11	465	43	$4,341	$10,812	$29,630
-	62	-	62	62	$0	$1,800	$5,692
-	3	-	3	79	$0	$34	$351
69	35	-	104	102	$8,479	$802	$15,700
-	-	28	28	60	$0	$0	$2,486
-	-	-	0	139	$0	$0	$0
54	-	-	54	285	$5,495	$0	$22,784
-	44	-	44	62	$0	$1,045	$4,039
-	12	-	12	102	$0	$287	$1,812
-	-	447	447	64	$0	$0	$42,376
-	-	8	8	21	$0	$0	$249
-	-	15	15	42	$0	$0	$932
-	-	41	41	54	$0	$0	$3,277
-	-	100	100	66	$0	$0	$9,768
-	-	1	1	39	$0	$0	$58
5	179	68	252	66	$265	$2,277	$24,615
-	-	23	23	94	$0	$0	$3,202
26	14	79	119	147	$1,585	$185	$25,904
7	1	3	11	374	$423	$15	$6,090
21	-	-	21	30	$1,351	$0	$932
8	123	23	154	66	$515	$1,712	$15,043
-	-	-	0	60	$0	$0	$0
-	-	36	36	30	$0	$0	$1,598
-	2	1	3	43	$0	$36	$191
-	-	64	64	62	$0	$0	$5,875
-	-	3	3	102	$0	$0	$453
-	-	-	0	163	$0	$0	$0
-	7	6	13	99	$0	$76	$1,905
-	2	-	2	156	$0	$22	$462
-	1	26	27	71	$0	$14	$2,838
17	-	10	27	156	$1,089	$0	$6,237
-	-	-	0	43	$0	$0	$0
-	-	-	0	43	$0	$0	$0
-	-	-	0	62	$0	$0	$0

d Revenue

Proposed Sch 91 & 95 A & B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	B	Annual Energy
-	-	332	332	32	$0	$0	$15,737
-	-	220	220	60	$0	$0	$4,884
-	143	4	147	60	$0	$2,196	$13,054
-	-	93	93	62	$0	$0	$8,537
-	10	73	83	102	$0	$241	$12,530
-	6	38	44	163	$0	$176	$10,618
19	10	-	29	30	$1,906	$188	$1,288
-	-	5	5	30	$0	$0	$222
-	-	1	1	66	$0	$0	$98
-	-	-	0	0	$0	$0	$0
142	549	4	695	30	$8,759	$6,852	$30,858
-	-	16	16	79	$0	$0	$1,872
-	-	21	21	31	$0	$0	$963
-	-	4	4	62	$0	$0	$367
30	222	7	259	66	$1,872	$2,930	$25,299
1	-	-	1	30	$53	$0	$44
39	5	-	44	43	$2,087	$64	$2,804
133	9	3	145	79	$9,448	$125	$16,965
-	-	-	0	124	$0	$0	$0
2	-	85	87	43	$0	$0	$5,544
-	-	2	2	86	$0	$0	$255
-	-	9	9	12	$0	$0	$160
1,794	-	-	1,794	11	$102,258	$0	$29,278
24,059	-	-	24,059	16	$1,362,702	$0	$568,755
4,765	-	-	4,765	18	$283,613	$0	$126,940
5,087	-	-	5,087	23	$314,987	$0	$173,365
2,226	-	-	2,226	36	$147,717	$0	$118,601
63	-	-	63	46	$4,604	$0	$4,294
170	-	-	170	60	$14,035	$0	$15,096
354	-	-	354	67	$30,501	$0	$35,131
-	-	-	0	8	$0	$0	$0
1,338	-	-	1,338	53	$112,231	$0	$105,006
4,544	-	-	4,544	9	$244,831	$0	$60,526
1,144	-	-	1,144	15	$63,423	$0	$25,397
1,425	-	-	1,425	30	$89,091	$0	$63,270
-	-	-	0	13	$0	$0	$0
-	-	-	0	20	$0	$0	$0
-	-	-	0	21	$0	$0	$0
-	-	-	0	25	$0	$0	$0
-	-	-	0	26	$0	$0	$0
-	-	-	0	28	$0	$0	$0
-	-	-	0	32	$0	$0	$0
-	-	-	0	33	$0	$0	$0
-	-	-	0	39	$0	$0	$0
-	-	-	0	43	$0	$0	$0
-	-	-	0	50	$0	$0	$0
-	-	-	0	56	$0	$0	$0
-	-	-	0	63	$0	$0	$0
267	-	-	267	16	$31,111	$0	$6,312
231	-	-	231	23	$32,349	$0	$7,872
1	-	-	1	13	$140	$0	$19
936	-	-	936	20	$131,414	$0	$27,743
97	-	-	97	25	$13,619	$0	$3,585
-	-	-	0	15	$0	$0	$0
-	-	-	0	18	$0	$0	$0
-	-	-	0	21	$0	$0	$0
61	-	-	61	18	$10,109	$0	$1,625
-	-	-	0	24	$0	$0	$0
2	-	-	2	29	$347	$0	$86
1,005	-	-	1,005	18	$172,096	$0	$26,773
8	-	-	8	23	$1,439	$0	$273
8	-	-	8	28	$1,456	$0	$331
5	-	-	5	12	$785	$0	$89
352	-	-	352	13	$55,926	$0	$6,758
-	-	-	0	15	$0	$0	$0
-	-	-	0	16	$0	$0	$0

d Revenue

Proposed Sch 91 & 95 A & B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	B	Annual Energy
-	-	-	0	20	$0	$0	$0
-	-	-	0	21	$0	$0	$0
-	-	-	0	25	$0	$0	$0
-	-	-	0	26	$0	$0	$0
7,314	-	-	7,314	11	$541,529	$0	$119,364
11	-	-	11	16	$857	$0	$260
270	-	-	270	24	$50,479	$0	$9,590
25	-	-	25	43	$2,007	$0	$1,593
71	-	-	71	63	$6,552	$0	$6,620
7	-	-	7	127	$996	$0	$1,316
1	-	-	1	28	$74	$0	$41
54	-	-	54	8	$0	$0	$642
34,769	-	-	34,769	9	$0	$0	$463,123
1,412	-	-	1,412	11	$0	$0	$23,044
6,351	-	-	6,351	13	$0	$0	$121,939
3,943	-	-	3,943	15	$0	$0	$87,535
1,568	-	-	1,568	16	$0	$0	$37,068
6,451	-	-	6,451	18	$0	$0	$171,855
167	-	-	167	20	$0	$0	$4,950
8,054	-	-	8,054	21	$0	$0	$250,318
516	-	-	516	23	$0	$0	$17,585
957	-	-	957	25	$0	$0	$35,371
19	-	-	19	26	$0	$0	$732
2,353	-	-	2,353	28	$0	$0	$97,414
4,012	-	-	4,012	30	$0	$0	$178,133
-	-	-	0	32	$0	$0	$0
45	-	-	45	33	$0	$0	$2,198
1,696	-	-	1,696	36	$0	$0	$90,363
1	-	-	1	39	$0	$0	$58
20	-	-	20	43	$0	$0	$1,274
2,750	-	-	2,750	46	$0	$0	$187,440
13	-	-	13	50	$0	$0	$963
1,027	-	-	1,027	53	$0	$0	$80,599
157	-	-	157	56	$0	$0	$13,018
128	-	-	128	60	$0	$0	$11,366
1,000	-	-	1,000	63	$0	$0	$93,240
53	-	-	53	67	$0	$0	$5,260
18	-	-	18	70	$0	$0	$1,866
2	-	-	2	0	$0	$0	$0
623	-	-	623	80	$0	$0	$73,788
-	-	-	0	0	$0	$0	$0
372	-	-	372	84	$0	$0	$46,247
-	-	-	0	87	$0	$0	$0
-	-	-	0	0	$0	$0	$0
17	-	-	17	94	$0	$0	$2,366
-	-	-	0	0	$0	$0	$0
-	-	-	0	0	$0	$0	$0
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139,678	**12,980**	**6,524**	**159,182**	**9,540**	**$4,135,321**	**$221,663**	**$5,714,964**

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	Black	Fiberglass	20	A	$4.61	5,368	$296,958
59	Bronze	Fiberglass	30	A	$7.49	2,821	$253,551
61	Gray	Fiberglass	30	A	$7.49	6,298	$566,064
1	Standard	Wood	30 to 35	A	$5.58	1,405	$94,079
3	Standard	Wood	40 to 55	A	$6.57	184	$14,507
58	Black	Fiberglass	20	B	$0.17	4,377	$8,929
60	Bronze	Fiberglass	30	B	$0.28	4,081	$13,712
62	Gray	Fiberglass	30	B	$0.28	7,541	$25,338
46	Standard	Wood	30 to 35	B	$0.21	139	$350
47	Standard	Wood	40 to 55	B	$0.25	43	$129
31	Regular	Aluminum	16	A	$4.26	573	$29,292
32	Regular	Aluminum	25	A	$7.92	3,089	$293,579
33	Regular	Aluminum	30	A	$9.09	326	$35,560
28	Regular	Aluminum	35	A	$10.52	109	$13,760
18	Davit	Aluminum	25	A	$8.45	43	$4,360
6	Davit	Aluminum	30	A	$9.52	652	$74,484
29	Davit	Aluminum	35	A	$10.88	657	$85,778
70	Davit with 8-foot Arm	Aluminum	40	A	$13.97	103	$17,267
27	Double Davit	Aluminum	30	A	$10.56	91	$11,532
65	Fluted Victorian Ornamental	Aluminum	14	A	$7.51	196	$17,664
69	Non-fluted Techtra Ornamental	Aluminum	18	A	$16.41	571	$112,441
66	Fluted Ornamental	Aluminum	16	A	$7.79	742	$69,362
77	HADCO Non-fluted Ornamental	Aluminum	16	A	$0.00	0	$0
79	Fluted Westbrooke	Aluminum	18	A	$15.42	97	$17,949
81	Aluminum, Non-Fluted Ornamental, Pendant	Aluminum	22	A	$15.32	1,682	$309,219
85	Decorative Ameron	Concrete	20	A	$8.87	0	$0
63	Fluted Ornamental -Black	Fiberglass	14	A	$10.51	687	$86,644
83	Smooth	Fiberglass	18	A	$4.89	6	$352
67	Regular - Color may vary	Fiberglass	22	A	$4.28	70	$3,595
68	Regular - Color may vary	Fiberglass	35	A	$7.31	564	$49,474
16	Anchor Base -Gray	Fiberglass	35	A	$9.98	53	$6,347
35	Direct Bury with Shroud	Fiberglass	18	A	$6.30	6	$454
34	Regular	Aluminum	16	B	$0.16	50	$96
8	Regular	Aluminum	25	B	$0.30	758	$2,729
48	Regular	Aluminum	30	B	$0.34	506	$2,064
54	Regular	Aluminum	35	B	$0.40	393	$1,886
13	Davit	Aluminum	25	B	$0.32	120	$461
12	Davit	Aluminum	30	B	$0.36	724	$3,128
53	Davit	Aluminum	35	B	$0.41	1,041	$5,122
76	Davit with 8-foot Arm	Aluminum	40	B	$0.53	268	$1,704
14	Double Davit	Aluminum	30	B	$0.40	58	$278
71	Fluted Victorian Ornamental	Aluminum	14	B	$0.28	1,153	$3,874
75	Non-fluted Techtra Ornamental	Aluminum	18	B	$0.62	438	$3,259
72	Fluted Ornamental	Aluminum	16	B	$0.30	1,132	$4,075
78	HADCO Non-fluted Ornamental	Aluminum	16	B	$0.00	0	$0
80	Fluted Westbrooke	Aluminum	18	B	$0.58	447	$3,111
82	Aluminum, Non-Fluted Ornamental, Pendant	Aluminum	22	B	$0.58	179	$1,246

PORTLAND GENERAL ELECTRIC
Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
44	Painted Ornamental - Portland Rd.	Aluminum	35	B	$0.00	61	$0
91	Aluminum, Regular with Breakaway Base	Aluminum	35	A	$15.07	0	$0
92	Aluminum, Regular with Breakaway Base	Aluminum	35	B	$0.57	0	$0
93	Aluminum, Double-Arm, Smooth Ornamental	Aluminum	18	A	$12.65	0	$0
86	Decorative Ameron	Concrete	20	B	$0.00	0	$0
87	Aluminum, Double-Arm, Smooth Ornamental	Aluminum	18	B	$0.48	0	$0
88	Fiberglass, Anchor Base, Color May Vary	Fiberglass	25	B	$0.34	15	$61
89	Fiberglass, Anchor Base, Color May Vary	Fiberglass	23	B	$0.41	0	$0
64	Fluted Ornamental -Black	Fiberglass	14	B	$0.40	1,447	$6,946
84	Smooth	Fiberglass	18	B	$0.19	0	$0
73	Regular - Color may vary	Fiberglass	22	B	$0.16	366	$703
74	Regular - Color may vary	Fiberglass	35	B	$0.28	1,482	$4,980
17	Anchor Base -Gray	Fiberglass	35	B	$0.38	97	$442
36	Direct Bury with Shroud	Fiberglass	18	B	$0.24	353	$1,017
2	Post	Aluminum	30	A	$4.26	346	$17,688
30	Ornamental Post	Concrete	35 or less	A	$7.92	57	$5,417
37	Painted Regular	Steel	25	A	$7.92	293	$27,847
38	Painted Regular	Steel	30	A	$9.09	135	$14,726
39	Laminated without Mast Arm	Wood	20	A	$4.61	0	$0
24	Laminted SLO Pole	Wood	20	A	$4.61	0	$0
41	Curved laminated	Wood	30	A	$6.40	0	$0
11	Painted Underground	Wood	35	A	$5.58	9	$603
55	Bronze Alloy GardCo	Bronze	12	B	$0.23	0	$0
25	Ornamental Post	Concrete	35 or less	B	$0.30	0	$0
7	Painted Regular	Steel	25	B	$0.30	108	$389
49	Painted Regular	Steel	30	B	$0.34	0	$0
21	Unpainted with 6-foot Mast Arm	Steel	30	B	$0.36	11	$48
51	Unpainted with 6-foot Davit Arm	Steel	30	B	$0.36	0	$0
40	Unpainted with 8-foot Mast Arm	Steel	35	B	$0.41	191	$940
42	Unpainted with 8-foot Davit Arm	Steel	35	B	$0.41	0	$0
23	Laminated without Mast Arm	Wood	20	B	$0.17	954	$1,946
45	Curved laminated	Wood	30	B	$0.28	75	$252
26	Painted Underground	Wood	35	B	$0.21	195	$491
				Total Option As		27,233	$2,530,552
				Total Option Bs		28,803	$99,706
						56,036	$2,630,257

PORTLAND GENERAL EL

Schedule 15, Proposed Tariff Prices, C

Code	Description	Type	Size	kWh	Monthly Tariff Price Fixed	Energy	Total
Fixtures							
3	Techtra	QL	165-watt	60	$18.70	$7.36	$26.06
21	Cobrahead	MV	175-watt	66	$4.34	$8.10	$12.44
23	Cobrahead	MV	400-watt	147	$4.79	$18.04	$22.83
24	Cobrahead	MV	1000-watt	374	$4.74	$45.89	$50.63
33	Cobrahead - (non-pd)	HPS	70-watt	30	$4.63	$3.68	$8.31
34	Cobrahead - (non-pd)	HPS	100-watt	43	$4.33	$5.28	$9.61
35	Cobrahead - (non-pd)	HPS	150-watt	62	$4.39	$7.61	$12.00
39	Cobrahead - (non-pd)	HPS	200-watt	79	$4.82	$9.69	$14.51
36	Cobrahead - (non-pd)	HPS	250-watt	102	$4.43	$12.52	$16.95
41	Cobrahead - (PD)	HPS	310-watt	124	$4.63	$15.22	$19.85
37	Cobrahead - (non-pd)	HPS	400-watt	163	$4.62	$20.00	$24.62
30	Flood	HPS	100-watt	43	$4.38	$5.28	$9.66
38	Flood	HPS	200-watt	79	$5.63	$9.69	$15.32
31	Flood	HPS	250-watt	102	$5.74	$12.52	$18.26
32	Flood	HPS	400-watt	163	$5.74	$20.00	$25.74
76	Shoebox	HPS	70-watt	30	$4.89	$3.68	$8.57
77	Shoebox	HPS	100-watt	43	$5.34	$5.28	$10.62
78	Shoebox	HPS	150-watt	62	$5.73	$7.61	$13.34
81	Special Acorn	HPS	100-watt	43	$8.17	$5.28	$13.45
82	HADCO - Victorian	HPS	150-watt	62	$8.17	$7.61	$15.78
49	HADCO - Victorian	HPS	200-watt	79	$8.49	$9.69	$18.18
83	HADCO - Victorian	HPS	250-watt	102	$8.40	$12.52	$20.92
40	Early American Post-Top	HPS	100-watt	43	$5.22	$5.28	$10.50
62	Cobrahead	MH	150-watt	60	$4.75	$7.36	$12.11
48	Cobrahead	MH	175-watt	71	$5.00	$8.71	$13.71
61	Flood	MH	350-watt	139	$6.75	$17.06	$23.81
60	Flood	MH	400-watt	156	$5.05	$19.14	$24.19
47	Flood	HPS	750-watt	285	$8.19	$34.97	$43.16
12	HADCO Independence	HPS	100-watt	43	$9.27	$5.28	$14.55
64	HADCO Capitol Acorn	HPS	100-watt	43	$11.89	$5.28	$17.17
65	HADCO Capitol Acorn	HPS	200-watt	79	$12.13	$9.69	$21.82
66	HADCO Capitol Acorn	HPS	250-watt	102	$3.45	$12.52	$15.97
98	HADCO Techtra	HPS	100-watt	43	$15.96	$5.28	$21.24
99	HADCO Techtra	HPS	150-watt	62	$16.72	$7.61	$24.33
90	HADCO Westbrooke	HPS	70-watt	30	$11.24	$3.68	$14.92
91	HADCO Westbrooke	HPS	100-watt	43	$11.39	$5.28	$16.67
94	HADCO Westbrooke	HPS	250-watt	102	$9.95	$12.52	$22.47
9	Holophane Mongoose	HPS	150-watt	62	$10.28	$7.61	$17.89
100	Cobrahead	LED	>30W-35W	11	$2.66	$1.35	$4.01
101	Cobrahead	LED	>45W-50W	16	$2.63	$1.96	$4.59
102	Cobrahead	LED	>50W-55W	18	$2.87	$2.21	$5.08
103	Cobrahead	LED	>65W-70W	23	$3.08	$2.82	$5.90
104	Cobrahead	LED	>100W-110W	36	$3.44	$4.42	$7.86
105	Cobrahead	LED	>130W-140W	46	$5.80	$5.64	$11.44
106	Cobrahead	LED	0	0	$0.00	$0.00	$0.00
107	Cobrahead	LED	>170W-180W	60	$6.59	$7.36	$13.95
108	Cobrahead	LED	>190W-200W	67	$6.89	$8.22	$15.11
110	Acorn	LED	>45W-50W	16	$9.43	$1.96	$11.39
111	Acorn	LED	>65W-70W	23	$11.38	$2.82	$14.20
112	Pendant (non-flare)	LED	53	18	$13.52	$2.21	$15.73
113	Pendant (non-flare)	LED	69	24	$13.64	$2.95	$16.59
114	Pendant (non-flare)	LED	85	29	$14.16	$3.56	$17.72
117	Pendant (flare)	LED	>50W-55W	18	$13.98	$2.21	$16.19
118	Pendant (flare)	LED	>65W-70W	23	$14.70	$2.82	$17.52
119	Pendant (flare)	LED	>80W-85W	28	$14.88	$3.44	$18.32

PORTLAND GENERAL EL

Schedule 15, Proposed Tariff Prices, C

Code	Description	Type	Size	kWh	Monthly Tariff Price Fixed	Energy	Total
122	CREE XSP	LED	>20W-25W	8	$2.26	$0.98	$3.24
123	CREE XSP	LED	>40W-45W	15	$2.26	$1.84	$4.10
124	CREE XSP	LED	>45W-50W	16	$2.50	$1.96	$4.46
125	CREE XSP	LED	>55W-60W	20	$2.30	$2.45	$4.75
126	CREE XSP	LED	>90W-95W	32	$2.63	$3.93	$6.56
127	Pendant (non-flare)	LED	36	12	$10.99	$1.47	$12.46
128	Pendant (flare)	LED	>35W-40W	13	$11.15	$1.60	$12.75
129	Post-Top, American Revolution	LED	>30W-35W	11	$4.08	$1.35	$5.43
130	Post-Top, American Revolution	LED	>45W-50W	16	$4.40	$1.96	$6.36
131	HADCO Acorn	LED	70	24	$13.49	$2.95	$16.44
132	Cobrahead	LED	>150W-160W	53	$12.62	$6.50	$19.12
133	Cobrahead	LED	>25W-30W	9	$12.71	$1.10	$13.81
134	Cobrahead	LED	>40W-45W	15	$5.84	$1.84	$7.68
135	Cobrahead	LED	>85W-90W	30	$6.17	$3.68	$9.85
137	Acorn	LED	>35W-40W	13	$6.83	$1.60	$8.43
138	Acorn	LED	>55W-60W	20	$4.40	$2.45	$6.85
139	Acorn	LED	>70W-75W	25	$4.53	$3.07	$7.60
141	Flood	LED	>120W-130W	43	$3.03	$5.28	$8.31
142	Flood	LED	>180W-190W	63	$11.31	$7.73	$19.04
143	Flood	LED	>370W-380W	127	$11.42	$15.58	$27.00
144	Flood	LED	>80W-85W	28	$11.26	$3.44	$14.70
200	Cobrahead	LED	>35W-40W	13	$2.97	$1.60	$4.57
201	Cobrahead	LED	>55W-60W	20	$6.34	$2.45	$8.79
202	Cobrahead	LED	>60W-65W	21	$7.31	$2.58	$9.89
203	Cobrahead	LED	>70W-75W	25	$11.39	$3.07	$14.46
204	Cobrahead	LED	>75W-80W	26	$5.88	$3.19	$9.07
205	Cobrahead	LED	>80W-85W	28	$4.23	$3.44	$7.67
206	Cobrahead	LED	>90W-95W	32	$4.37	$3.93	$8.30
207	Cobrahead	LED	>95W-100W	33	$4.37	$4.05	$8.42
208	Cobrahead	LED	>110W-120W	39	$4.95	$4.79	$9.74
209	Cobrahead	LED	>120W-130W	43	$4.95	$5.28	$10.23
210	Cobrahead	LED	>140W-150W	50	$5.01	$6.14	$11.15
211	Cobrahead	LED	>160W-170W	56	$5.01	$6.87	$11.88
212	Cobrahead	LED	>180W-190W	63	$5.02	$7.73	$12.75
213	Acorn	LED	>40W-45W	15	$5.15	$1.84	$6.99
214	Acorn	LED	>50W-55W	18	$5.16	$2.21	$7.37
215	Acorn	LED	>60W-65W	21	$6.90	$2.58	$9.48
216	Pendant (flare)	LED	>40W-45W	15	$6.95	$1.84	$8.79
217	Pendant (flare)	LED	>45W-50W	16	$6.95	$1.96	$8.91
218	Pendant (flare)	LED	>55W-60W	20	$11.58	$2.45	$14.03
219	Pendant (flare)	LED	>60W-65W	21	$11.58	$2.58	$14.16
220	Pendant (flare)	LED	>70W-75W	25	$11.61	$3.07	$14.68
221	Pendant (flare)	LED	>75W-80W	26	$13.12	$3.19	$16.31
222	CREE XSP	LED	>30W-35W	11	$12.82	$1.35	$14.17
223	CREE XSP	LED	>65W-70W	23	$13.84	$2.82	$16.66
224	CREE XSP	LED	>130W-140W	46	$13.89	$5.64	$19.53
Totals							

PORTLAND GENERAL EL
Schedule 15, Proposed Tariff Prices, C

Code	Description	Type	Size	kWh	Monthly Tariff Price Fixed	Energy	Total
Poles							
1	Standard	Wood	30 to 35				$5.32
3	Standard	Wood	40 to 55				$6.31
11	Painted Underground	Wood	35				$5.32
41	Curved laminated	Wood	30				$6.32
31	Regular	Aluminum	16				$4.07
32	Regular	Aluminum	25				$7.59
33	Regular	Aluminum	30				$8.76
28	Regular	Aluminum	35				$10.19
65	Fluted Ornamental	Aluminum	14				$7.31
18	Davit	Aluminum	25				$8.12
6	Davit	Aluminum	30				$9.19
29	Davit	Aluminum	35				$10.55
70	Davit with 8-foot Arm	Aluminum	40				$13.58
27	Double Davit	Aluminum	30				$10.23
66	HADCO, Fluted Ornamental	Aluminum	16				$7.59
69	HADCO, Non-fluted Techtra Ornamental	Aluminum	18				$16.08
63	Fluted Ornamental Black	Fiberglass	14				$9.82
57	Regular Black	Fiberglass	20				$4.41
61	Regular Gray	Fiberglass	30				$7.16
68	Regular Other Colors	Fiberglass	35				$7.05
16	Anchor Base Gray	Fiberglass	35				$9.71
35	Direct Bury with Shroud	Fiberglass	18				$5.97
79	Fluted Westbrooke	Aluminum	18				$15.09
81	Aluminum, Non-Fluted Ornamental, Pendant	Aluminum	22				$14.99
85	Fiberglass, ANCHOR BASE, COLOR MAY V	Fiberglass	25				$10.22
86	Fiberglass, ANCHOR BASE, COLOR MAY V	Fiberglass	30				$13.87
Totals							
Totals Luminaires and Poles							

ECTRIC

ounts and Revenue

DAX Monthly Tariff Price				Annual	Revenues		
Fixed	**Energy**	**Total**	**Count**	**MWh**	**Fixed**	**Energy**	**Total**
$18.70	$4.24	$22.94	1	1	$224	$88	$313
$4.34	$4.66	$9.00	227	180	$11,822	$22,064	$33,887
$4.79	$10.39	$15.18	377	665	$21,670	$81,613	$103,283
$4.74	$26.43	$31.17	57	256	$3,242	$31,389	$34,631
$4.63	$2.12	$6.75	87	31	$4,834	$3,842	$8,676
$4.33	$3.04	$7.37	55	28	$2,858	$3,485	$6,343
$4.39	$4.38	$8.77	11	8	$579	$1,005	$1,584
$4.82	$5.58	$10.40	24	23	$1,388	$2,791	$4,179
$4.43	$7.21	$11.64	15	18	$797	$2,254	$3,051
$4.63	$8.76	$13.39	6	9	$333	$1,096	$1,429
$4.62	$11.52	$16.14	903	1,766	$50,062	$216,720	$266,782
$4.38	$3.04	$7.42	370	191	$19,447	$23,443	$42,890
$5.63	$5.58	$11.21	662	628	$44,725	$76,977	$121,702
$5.74	$7.21	$12.95	746	913	$51,384	$112,079	$163,464
$5.74	$11.52	$17.26	1,938	3,791	$133,489	$465,120	$598,609
$4.89	$2.12	$7.01	10	4	$587	$442	$1,028
$5.34	$3.04	$8.38	522	269	$33,450	$33,074	$66,524
$5.73	$4.38	$10.11	104	77	$7,151	$9,497	$16,648
$8.17	$3.04	$11.21	347	179	$34,020	$21,986	$56,006
$8.17	$4.38	$12.55	21	16	$2,059	$1,918	$3,977
$8.49	$5.58	$14.07	0	0	$0	$0	$0
$8.40	$7.21	$15.61	0	0	$0	$0	$0
$5.22	$3.04	$8.26	148	76	$9,271	$9,377	$18,648
$4.75	$4.24	$8.99	11	8	$627	$972	$1,599
$5.00	$5.02	$10.02	3	3	$180	$314	$494
$6.75	$9.82	$16.57	588	981	$47,628	$120,375	$168,003
$5.05	$11.03	$16.08	815	1,526	$49,389	$187,189	$236,578
$8.19	$20.14	$28.33	83	284	$8,157	$34,830	$42,987
$9.27	$3.04	$12.31	3	2	$334	$190	$524
$11.89	$3.04	$14.93	0	0	$0	$0	$0
$12.13	$5.58	$17.71	0	0	$0	$0	$0
$3.45	$7.21	$10.66	0	0	$0	$0	$0
$15.96	$3.04	$19.00	14	7	$2,681	$887	$3,568
$16.72	$4.38	$21.10	5	4	$1,003	$457	$1,460
$11.24	$2.12	$13.36	0	0	$0	$0	$0
$11.39	$3.04	$14.43	0	0	$0	$0	$0
$9.95	$7.21	$17.16	0	0	$0	$0	$0
$10.28	$4.38	$14.66	0	0	$0	$0	$0
$2.66	$0.78	$3.44	71	9	$2,254	$1,144	$3,398
$2.63	$1.13	$3.76	348	67	$10,975	$8,179	$19,153
$2.87	$1.27	$4.14	98	21	$3,390	$2,611	$6,001
$3.08	$1.63	$4.71	159	44	$5,892	$5,395	$11,287
$3.44	$2.54	$5.98	163	70	$6,714	$8,626	$15,340
$5.80	$3.25	$9.05	81	45	$5,660	$5,504	$11,163
$0.00	$0.00	$0.00	0	0	$0	$0	$0
$6.59	$4.24	$10.83	62	45	$4,908	$5,481	$10,388
$6.89	$4.74	$11.63	315	253	$26,009	$31,029	$57,038
$9.43	$1.13	$10.56	16	3	$1,816	$377	$2,194
$11.38	$1.63	$13.01	5	1	$731	$181	$912
$13.52	$1.27	$14.79	0	0	$0	$0	$0
$13.64	$1.70	$15.34	0	0	$0	$0	$0
$14.16	$2.05	$16.21	0	0	$0	$0	$0
$13.98	$1.27	$15.25	0	0	$0	$0	$0
$14.70	$1.63	$16.33	0	0	$0	$0	$0
$14.88	$1.98	$16.86	0	0	$0	$0	$0

ECTRIC
ounts and Revenue

DAX Monthly Tariff Price				Annual		Revenues		
Fixed	**Energy**	**Total**	**Count**	**MWh**		**Fixed**	**Energy**	**Total**
$2.26	$0.57	$2.83	1,010	97		$27,392	$11,878	$39,271
$2.26	$1.06	$3.32	6,340	1,141		$171,928	$139,977	$311,905
$2.50	$1.13	$3.63	1,022	196		$30,654	$24,033	$54,688
$2.30	$1.41	$3.71	2,292	550		$63,255	$67,381	$130,636
$2.63	$2.26	$4.89	982	377		$30,999	$46,322	$77,321
$10.99	$0.85	$11.84	0	0		$0	$0	$0
$11.15	$0.92	$12.07	0	0		$0	$0	$0
$4.08	$0.78	$4.86	16	2		$786	$260	$1,046
$4.40	$1.13	$5.53	0	0		$0	$0	$0
$13.49	$1.70	$15.19	0	0		$0	$0	$0
$12.62	$3.75	$16.37	106	67		$16,041	$8,262	$24,304
$12.71	$0.64	$13.35	50	5		$7,670	$664	$8,334
$5.84	$1.06	$6.90	93	17		$6,524	$2,055	$8,579
$6.17	$2.12	$8.29	73	26		$5,387	$3,213	$8,600
$6.83	$0.92	$7.75	0	0		$0	$0	$0
$4.40	$1.41	$5.81	3	1		$169	$94	$264
$4.53	$1.77	$6.30	0	0		$0	$0	$0
$3.03	$3.04	$6.07	77	40		$2,801	$4,881	$7,682
$11.31	$4.45	$15.76	339	256		$46,033	$31,462	$77,495
$11.42	$8.98	$20.40	131	199		$17,889	$24,405	$42,293
$11.26	$1.98	$13.24	19	6		$2,602	$795	$3,397
$2.97	$0.92	$3.89	0	0		$0	$0	$0
$6.34	$1.41	$7.75	0	0		$0	$0	$0
$7.31	$1.48	$8.79	0	0		$0	$0	$0
$11.39	$1.77	$13.16	0	0		$0	$0	$0
$5.88	$1.84	$7.72	0	0		$0	$0	$0
$4.23	$1.98	$6.21	0	0		$0	$0	$0
$4.37	$2.26	$6.63	0	0		$0	$0	$0
$4.37	$2.33	$6.70	0	0		$0	$0	$0
$4.95	$2.76	$7.71	0	0		$0	$0	$0
$4.95	$3.04	$7.99	0	0		$0	$0	$0
$5.01	$3.53	$8.54	0	0		$0	$0	$0
$5.01	$3.96	$8.97	0	0		$0	$0	$0
$5.02	$4.45	$9.47	0	0		$0	$0	$0
$5.15	$1.06	$6.21	0	0		$0	$0	$0
$5.16	$1.27	$6.43	0	0		$0	$0	$0
$6.90	$1.48	$8.38	0	0		$0	$0	$0
$6.95	$1.06	$8.01	0	0		$0	$0	$0
$6.95	$1.13	$8.08	0	0		$0	$0	$0
$11.58	$1.41	$12.99	0	0		$0	$0	$0
$11.58	$1.48	$13.06	0	0		$0	$0	$0
$11.61	$1.77	$13.38	0	0		$0	$0	$0
$13.12	$1.84	$14.96	0	0		$0	$0	$0
$12.82	$0.78	$13.60	0	0		$0	$0	$0
$13.84	$1.63	$15.47	0	0		$0	$0	$0
$13.89	$3.25	$17.14	0	0		$0	$0	$0
			22,023	15,482	0	1,041,648	1,899,593	2,941,241

ECTRIC
ounts and Revenue

DAX Monthly Tariff Price				Annual	Revenues		
Fixed	Energy	Total	Count	MWh	Fixed	Energy	Total
			6,025				$384,636
			658				$49,824
			1				$64
			0				$0
			41				$2,002
			19				$1,731
			11				$1,156
			6				$734
			36				$3,158
			4				$390
			18				$1,985
			1				$127
			0				$0
			13				$1,596
			2				$182
			19				$3,666
			159				$18,737
			372				$19,686
			1,434				$123,209
			47				$3,976
			2				$233
			112				$8,024
			0				$0
			0				$0
			0				$0
			0				$0
			8,980				$625,115
							$3,566,356

PORTLAND GENERAL ELECTRIC
Proposed Line Extension Allowances

Exhibit
Current and Proposed Line Extension Prices

Schedule	Current LEA Price	Proposed LEA Price		Notes:
Schedule 7-Primary Other	$1,590.00	$1,867	dwelling unit	Three times annual Basic & Distribution revenues
Schedule 7-All Electric	$2,260.00	$2,660	dwelling unit	Three times annual Basic & Distribution revenues
Sch 32	$0.1473	$0.2637	estimated annual kWh	Four times annual Basic & Distribution revenues
Sch 38, 83	$0.0780	$0.1082	estimated annual kWh	Four times annual Basic & Distribution revenues
Sch 85 & 89 Secondary	$0.0531	$0.0791	estimated annual kWh	Four times annual Basic & Distribution revenues
Sch 85 & 89 Primary	$0.0264	$0.0474	estimated annual kWh	Four times annual Basic & Distribution revenues
Sch 15, 91 & 95	$0.0850	$0.1992	estimated annual kWh	Optional Schedule: Three times annual Distribution revenues
Sch 92	$0.0531	$0.0521	estimated annual kWh	Optional Schedule: Three times annual Distribution revenues
Sch 47 & 49	$0.0336	$0.0995	estimated annual kWh	Optional Schedule: One times annual Distribution revenues

Schedule	Basic Charge Revenues	Distribution Revenues	Subtotal Revenues	MWh	cents/kWh	Multiplier	LEA @ Multiplier times cents/kWh	Primary Other Electric kWh	All Electric kWh
Sch 7	$106,792,774	$409,276,771	$516,069,545	7,555,010	$0.0683	3	$0.2049	9110	12980
Sch 15	0	$1,280,322	$1,280,322	14,480	$0.0884	3	$0.2653		
Sch 32	$27,151,961	$76,765,376	$103,917,337	1,576,157	$0.0659	4	$0.2637		
Sch 38	$135,840	$2,166,293	$2,302,133	31,528	$0.0730	4	$0.2921		
Sch 47	$616,050	$2,223,522	$2,839,572	20,075	$0.1414	1	$0.1414		
Sch 49	$379,350	$4,887,710	$5,267,060	61,430	$0.0857	1	$0.0857		
Sch 83	$6,305,290	$67,967,395	$74,272,685	2,800,127	$0.0265	4	$0.1061		
Sch 85-S	$14,906,430	$27,526,020	$42,432,450	2,134,357	$0.0199	4	$0.0795		
Sch 85-P	$2,131,800	$7,622,586	$9,754,386	612,588	$0.0159	4	$0.0637		
Sch 89-S	$64,560	$0	$64,560	13,878	$0.0047	4	$0.0186		
Sch 89-P	$1,176,120	$3,003,351	$4,179,471	562,911	$0.0074	4	$0.0297		
Sch 91	$0	$727,696	$727,696	12,380	$0.0588	3	$0.1763		
Sch 92	$0	$44,719	$44,719	2,576	$0.0174	3	$0.0521		
Sch 95	$0	$1,731,424	$1,731,424	29,456	$0.0588	3	$0.1763		

Supportalbe LEA Multiplier

Calculation of Schedule 07 LEA

Line No	Description	Source		
1	Revenue from Schedule 07	Rev Prop	($000)	$1,082,624
2	Marginal Cost to Serve Schedule 07 Load	Marginal Cost $-kWh	($/MwH)	$100.89
3	Energy from Schedule 07	Rev Prop	MWh	7,555,010
4	Marginal Cost to Serve Schedule 07 Load	e 2 * Line 3/1000	($000)	$762,188
5	Net Margin from Schedule 07	Line 1 -Line 4	($000)	$320,436
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$5,022,509
8	Basic and Distribution Revenue from Schedule 07	Rev Prop	($000)	$516,070
9	Supportable Schedule 07 LEA (Mulitplier)	Line 7/ Line 8		9.732232473

Calculation of Schedule 32 LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 32	Rev Prop	($000)	$ 218,403
2	Marginal Cost to Serve Schedule 32 Load	Marginal Cost $-kWh	($/MwH)	$100.50
3	Energy from Schedule 32	Rev Prop	MWh	1,576,157
4	Marginal Cost to Serve Schedule 32Load	e 2 * Line 3/1000	($000)	$158,399
5	Net Margin from Schedule 32	Line 1 -Line 4	($000)	$ 60,003
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$ 940,487
8	Basic and Distribution Revenue from Schedule 32	Rev Prop	($000)	$103,917
9	Supportable Schedule 32 LEA (Mulitplier)	Line 7/ Line 8		9.05

Calculation of Schedule 38 LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 38	Rev Prop	($000)	$ 4,508
2	Marginal Cost to Serve Schedule 38 Load	Marginal Cost $-kWh	($/MwH)	$105.42
3	Energy from Schedule 38	Rev Prop	MWh	31,528
4	Marginal Cost to Serve Schedule 38 Load	e 2 * Line 3/1000	($000)	$3,324
5	Net Margin from Schedule 38	Line 1 -Line 4	($000)	$ 1,185
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$ 18,567
8	Basic and Distribution Revenue from Schedule 38	Rev Prop	($000)	$2,302
9	Supportable Schedule 38 LEA (Mulitplier)	Line 7/ Line 8		8.07

Calculation of Schedule 47 LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 47	Rev Prop	($000)	$ 4,435
2	Marginal Cost to Serve Schedule 47 Load	Marginal Cost $-kWh	($/MwH)	$142.29
3	Energy from Schedule 47	Rev Prop	MWh	20,075
4	Marginal Cost to Serve Schedule 47 Load	: 2 * Line 3/1000	($000)	$2,857
5	Net Margin from Schedule 47	Line 1 -Line 4	($000)	$ 1,578
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$ 24,737
8	Basic and Distribution Revenue from Schedule 47	Rev Prop	($000)	$2,840
9	Supportable Schedule 47 LEA (Mulitplier)	Line 7/ Line 8		8.71

Calculation of Schedule 49 LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 49	Rev Prop	($000)	$ 10,063
2	Marginal Cost to Serve Schedule 49 Load	Marginal Cost $-kWh	($/MwH)	$121.88
3	Energy from Schedule 49	Rev Prop	MWh	61,430
4	Marginal Cost to Serve Schedule 49 Load	: 2 * Line 3/1000	($000)	$7,487
5	Net Margin from Schedule 47	Line 1 -Line 4	($000)	$ 2,576
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$ 40,375
8	Basic and Distribution Revenue from Schedule 49	Rev Prop	($000)	$5,267
9	Supportable Schedule 49 LEA (Mulitplier)	Line 7/ Line 8		7.67

Calculation of Schedule 83 LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 83	Rev Prop	($000)	$ 298,930
2	Marginal Cost to Serve Schedule 83 Load	Marginal Cost $-kWh	($/MwH)	$80.10
3	Energy from Schedule 83	Rev Prop	MWh	2,800,127
4	Marginal Cost to Serve Schedule 83 Load	: 2 * Line 3/1000	($000)	$224,282
5	Net Margin from Schedule 47	Line 1 -Line 4	($000)	$ 74,648
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$ 1,170,039
8	Basic and Distribution Revenue from Schedule 83	Rev Prop	($000)	$74,273
9	Supportable Schedule 83 LEA (Mulitplier)	Line 7/ Line 8		15.75

Calculation of Schedule 85 LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 85	Rev Prop	($000)	$ 239,739
2	Marginal Cost to Serve Schedule 85 Load	Marginal Cost $-kWh	($/MwH)	$68.85
3	Energy from Schedule 85	Rev Prop	MWh	2,746,945
4	Marginal Cost to Serve Schedule 85 Load	: 2 * Line 3/1000	($000)	$189,136
5	Net Margin from Schedule 85	Line 1 -Line 4	($000)	$ 50,604
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$ 793,161
8	Basic and Distribution Revenue from Schedule 85	Rev Prop	($000)	$52,187
9	Supportable Schedule 85 LEA (Mulitplier)	Line 7/ Line 8		15.20

Calculation of Schedule 85S LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 85	Rev Prop	($000)	$ 188,854
2	Marginal Cost to Serve Schedule 85 Load	Marginal Cost $-kWh	($/MwH)	$68.85
3	Energy from Schedule 85	Rev Prop	MWh	2,134,357
4	Marginal Cost to Serve Schedule 85 Load	* Line 3/1000	($000)	$146,957
5	Net Margin from Schedule 85	.ine 1 -Line 4	($000)	$ 41,897
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	.ine 5/ Line 6	($000)	$ 656,691
8	Basic and Distribution Revenue from Schedule 85	Rev Prop	($000)	$42,432
9	Supportable Schedule 85 LEA (Mulitplier)	.ine 7/ Line 8		15.48

Calculation of Schedule 89 LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 89	Rev Prop	($000)	$ 43,294
2	Marginal Cost to Serve Schedule 89 Load	Marginal Cost $-kWh	($/MwH)	$59.44
3	Energy from Schedule 89	Rev Prop	MWh	616,608
4	Marginal Cost to Serve Schedule 89 Load	2 * Line 3/1000	($000)	$36,649
5	Net Margin from Schedule 89	Line 1 -Line 4	($000)	$ 6,645
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$ 104,154
8	Basic and Distribution Revenue from Schedule 89	Rev Prop	($000)	$4,244
9	Supportable Schedule 89 LEA (Mulitplier)	Line 7/ Line 8		24.54

Calculation of Schedule 91/95 LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 91/95	Rev Prop	($000)	$ 11,195
2	Marginal Cost to Serve Schedule 91/95 Load	Marginal Cost $-kWh	($/MwH)	$79.47
3	Energy from Schedule 91/95	Rev Prop	MWh	41,836
4	Marginal Cost to Serve Schedule 91/95 Load	2 * Line 3/1000	($000)	$3,325
5	Net Margin from Schedule 91/95	Line 1 -Line 4	($000)	$ 7,870
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$ 123,360
8	Basic and Distribution Revenue from Schedule 91/95	Rev Prop	($000)	$2,459
9	Supportable Schedule 91/95 LEA (Mulitplier)	Line 7/ Line 8		50.16

Calculation of Schedule 92 LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 92	Rev Prop	($000)	$ 207
2	Marginal Cost to Serve Schedule 92 Load	Marginal Cost $-kWh	($/MwH)	$63.45
3	Energy from Schedule 92	Rev Prop	MWh	2,576
4	Marginal Cost to Serve Schedule 92 Load	2 * Line 3/1000	($000)	$163
5	Net Margin from Schedule 92	Line 1 -Line 4	($000)	$ 44
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$ 689
8	Basic and Distribution Revenue from Schedule 92	Rev Prop	($000)	$45
9	Supportable Schedule 92 LEA (Mulitplier)	Line 7/ Line 8		15.40

Calculation of Schedule 15 LEA

Line No	Description	Source	Units	Value
1	Revenue from Schedule 15	Rev Prop	($000)	$ 3,602
2	Marginal Cost to Serve Schedule 15 Load	Marginal Cost $-kWh	($/MwH)	$62.38
3	Energy from Schedule 15	Rev Prop	MWh	14,480
4	Marginal Cost to Serve Schedule 15 Load	2 * Line 3/1000	($000)	$903
5	Net Margin from Schedule 15	Line 1 -Line 4	($000)	$ 2,699
6	Annualization Factor	Levelized Annual Rev Req		6.38%
7	Investment Supported by Revenue	Line 5/ Line 6	($000)	$ 42,298
8	Basic and Distribution Revenue from Schedule 15	Rev Prop	($000)	$1,280
9	Supportable Schedule 15 LEA (Mulitplier)	Line 7/ Line 8		33.04

PORTLAND GENERAL ELECTRIC
2022 Projected Line Loss Factors by Service Delivery Voltage

Delivery Voltage	Internal Loss Factor	External Loss Factor	Total Loss Factor
Secondary	1.96%	2.20%	4.16%
Primary	3.09%	2.20%	5.30%
Subtransmission	4.20%	2.20%	6.40%