BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Jim Piro
Jim Lobdell

February 28, 2017

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I. Introduction

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

A. My name is James J. Piro. I am the President and Chief Executive Officer of PGE.

My name is Jim Lobdell. I am the Senior Vice President, Finance, Chief Financial Officer, and Treasurer of PGE.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to:

- Summarize the proposed average price increase of approximately 5.6% and discuss our efforts to mitigate the impact of the price increase, in keeping with our long-term strategy of minimizing price volatility for customers;
- Describe the context of this filing and customers' expectations;
- Discuss PGE's continuous improvement efforts; and
- Identify our other key proposals.

Our testimony is organized according to these objectives.

Q. Please provide a brief description of PGE.

A. PGE is a vertically-integrated regulated electric utility company that proudly serves over 860,000 customers in 51 cities within Oregon. PGE's service territory includes 4,000 square miles, primarily in and around the Portland and Salem metropolitan areas. Our headquarters is in Portland, Oregon.

Q. Please state PGE's mission and core strategy.

A. PGE's mission is to be a company our customers and communities can depend on to provide electric service in a safe, sustainable and reliable manner, with excellent service, at a reasonable price.

Operational Excellence, Business Growth and Corporate Responsibility are the three foundational elements of PGE's business strategy to deliver on our commitment to our customers and stakeholders. In fulfilling this commitment, every employee plays a role that contributes to our collective success in delivering exceptional value to our customers.

Q. How do you manage the company to PGE's mission and core strategy?

A. PGE uses scorecards with clearly stated goals. Individual goals include metrics to measure performance in achieving those goals. The scorecards also include improvement plans that reduce cost or improve service to our customers. PGE's goals and improvement plans are informed by benchmarking various areas in the company and industry best practices.

II. Summary of Request

Q. Please summarize PGE's request in this rate case filing.

A. PGE requests that prices be adjusted to yield $99.9 million of additional revenues, which represents a 5.6% increase overall for cost of service and direct access customers beginning in January 2018 (see PGE Exhibits 200 and 1400 for more detail).

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

A. PGE's request is centered on keeping our system safe and reliable and meeting our customers' expectations for quality service. The specific drivers include:

- Strengthening the power grid to better prepare for cyber attacks, earthquakes, and other potential threats.
    - Cyber security – Described in PGE Exhibit 500, PGE is enhancing its cyber security program based on a risk-based prioritization of enterprise-wide cyber initiatives recommended by outside consultants. We need to be prepared for increasing foreign and domestic threats. Disruptions to the electric grid have the potential to affect medical and emergency services, customer's lives, and businesses.
    - Physical security/disaster preparedness/emergency management – We are continuing our journey on our business continuity and emergency management roadmap. The roadmap establishes the activities we need to perform to achieve a target level of preparedness and resilience commensurate with our role as a regional provider of a critical public service. Also, both PGE's expanding physical footprint and new regulations are increasing our security costs. Additional detail is provided in PGE Exhibit 600.

- Adopting new technologies to meet customers' changing energy needs and service expectations.
  - Customer Engagement Transformation (CET) – Outlined in PGE Exhibit 900 – we're replacing PGE's outdated customer information system (CIS) and meter data management system (MDMS). CET will help us improve the way we engage and serve our customers, implement better business processes, and provide more efficient billing through automation.
- Building a more flexible system that supports key initiatives, including our participation in the Western Energy Imbalance Market (EIM) beginning in late 2017.
  - Western EIM – PGE's participation in the Western EIM is the next phase of PGE's integrated approach to implementing solutions that enhance operational efficiency, integrate renewable resources, and optimize our generation portfolio. The Western EIM, its benefits, and costs in PGE's 2018 test year are discussed in PGE Exhibit 300.
- Building new infrastructure to support growth in our region and making strategic capital improvements to the Transmission and Distribution (T&D) system by reducing reliability risk.
  - Customer-Driven Capital Work – T&D is seeing an increase in customer-driven capital work, primarily in new customer connections. To keep up with the increased customer demand, T&D is increasing its capital labor as well as building new infrastructure (i.e., substations). This is discussed in more detail in PGE Exhibit 800.

- Strategic Capital Improvements for Risk Reduction – We're making upgrades to our T&D system, including replacing infrastructure that is reaching the end of its useful life. As described in PGE Exhibit 800, our Strategic Asset Management team developed a risk assessment methodology that uses best industry practices criteria to quantify threats to the grid and evaluate the impacts to customers should portions of the system fail. This methodology considers negative impacts on system reliability, public and worker safety, environmental stewardship, and efficient use expenditure funds.

- About $25 million in reduced revenues based on lower forecasted energy sales. PGE Exhibit 1200 shows PGE's loads are forecasted to decrease in 2018 relative to the forecast used to set prices for 2016. Without resetting prices, PGE will experience lower revenues and not fully recover its fixed costs.

Q. Are you proposing to improve efficiency in your operations?

A. Yes. PGE is driving efficiency in our operations to partially offset cost escalations in several areas, including: transmission, distribution, generation, and support services.

Q. What are you proposing to reduce the price increase in this rate case?

A. As our business grows, we have worked hard to keep costs down to offset the impact of inflation. To accomplish this we have taken a number of specific actions including: 1) we removed 100% of Officer Long-term Incentive Program costs and 50% of incentive compensation costs even though the entirety of the incentive program benefits customers and is a key part of PGE's total compensation; 2) we removed 50% of certain layers of directors and officers insurance; and 3) we requested a return on equity (ROE) in the low portion of the range supported by PGE's expert witness.

Q. Are you requesting recovery of the additions of the new CIS and MDMS as part of CET?

A. No, recovery of the capital costs associated with the new CIS and MDMS are not part of this case. Our considerations for cost recovery include a future general rate case (GRC) and/or a deferral filing. As discussed in PGE Exhibit 900, CET is on schedule to be completed in 2018.

Q. Are the proposed impacts to various customer schedules in this GRC similar to the impacts observed in PGE's previous two GRCs, UE 283 and UE 294?

A. No. In the two most recent GRCs, PGE was adding new generation plants. While rate spread provided varied impacts to the major customer schedules, the impacts were within a narrow range. Due to increases in distribution and information technology costs in this rate case, customer classes that use these services more intensively bear a higher burden as demonstrated in PGE Exhibit 1400. Table 1 below shows the proposed price changes associated with this case.

Table 1

Estimated Cost of Service Base Rate Impacts Inclusive of Schedules 122 and 146

Schedule	Jan. 1, 2018
Schedule 7 Residential	7.1%
Schedule 32 Small Nonresidential	5.7%
Schedule 83 31-200 kW	4.2%
Schedule 85 201-4,000 kW	3.5%
Schedule 89 Over 4,000 kW	1.2%
Schedule 90 100 MWa	1.2%
COS & DA Overall	5.6%

III. Context / Customers' Expectations

Q. What are your goals for PGE?

A. First and foremost: deliver safe, reliable and secure power – balanced with the need for reasonably priced electricity – to customers with excellent customer service while complying with all applicable laws and regulations. We have strong core values that reflect our commitment to our customers, employees, community and shareholders. If we continue to be successful, we will also: 1) continue to be viewed by our customers as a trusted energy partner; 2) be a preferred employer, attracting and retaining exceptional employee talent; 3) maintain our standing as a caring and invested community partner; and 4) attract capital investors by offering a competitive return on capital invested and maintaining investment grade ratings.

Q. What are you doing to meet your commitments to your customers?

A. PGE meets the needs of our customers by maintaining and delivering on service and reliability metrics that focus on what is important to our customers such as: providing reliable power supply with resources sufficient to meet 1 in 2 peak loads, responding quickly to outages, account services requests and inquiries; replacing infrastructure that has reached the end of its useful life, threatening system reliability and safety; protecting the system from external threats; providing excellent customer service; and implementing pilot programs that include proven technology to test customer interest, participation, and costs and benefits.

We are focused on balancing the service, reliability, and security our customers expect with keeping electricity prices reasonable. This balance is critical. If we short change service, reliability, and security; our customers are impacted with more frequent outages or poor service.

Q. Please discuss PGE's pursuit of operational excellence.

A. PGE pursues operational excellence in all aspects of its business. Operational excellence begins with keeping our customers, employees, and the general public safe as it relates to our electric infrastructure, as well as providing excellent customer service and reliability in transmission, distribution, generation, and power operations. PGE is doing many things to achieve operational excellence, including:

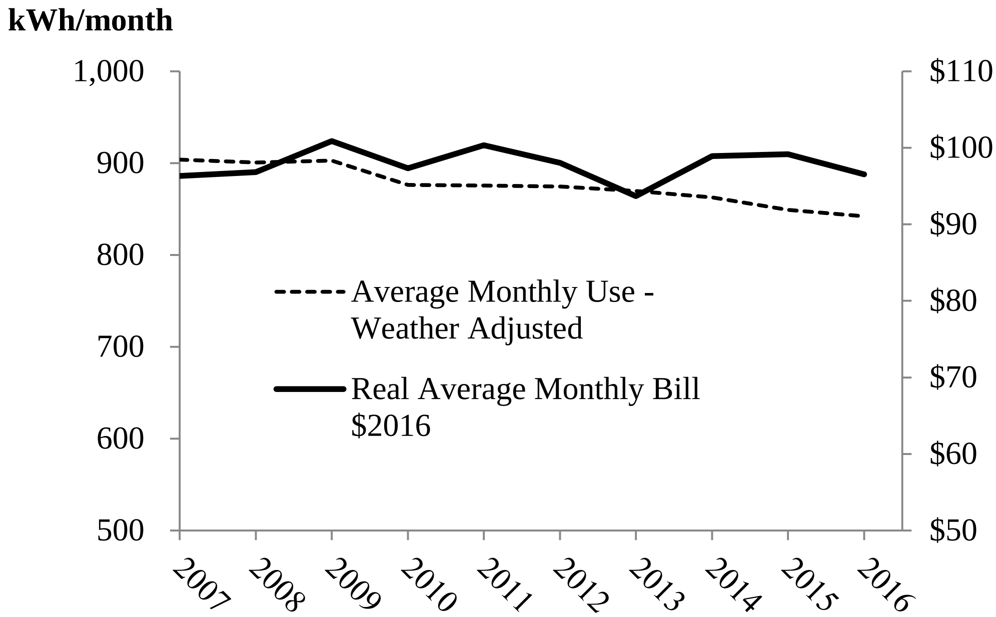
- Complying with regulations; maintaining the physical security of our assets, including seismic resilience; and cyber security;
- Participating in the Western EIM in order to enhance operational efficiency, integrate renewable resources, and optimize our generation portfolio;
- Deploying and leveraging technology to enhance efficiency and effectiveness which results in doing more with less over the long term; and
- Reworking processes to improve our efficiency, increase our customer responsiveness, and avoid cost increases through continuous improvement.

Additionally, we are committed to creating an engaged, valued and appropriately compensated workforce that, in turn, helps us achieve results on behalf of our customers. In addition to maintaining a compensation philosophy that targets the midpoint of the market, we must ensure our workforce initiatives help develop our employees to their highest potential to meet customer needs. PGE Exhibit 400 discusses these issues in more detail.

Q. How is PGE's business influenced by the economy?

A. Economic activity in our service territory drives greater demand on our systems and resources in the form of load growth. This load growth, and the net margin it produces, enables us to absorb normal inflationary cost increases. Over the last several years, industrial business sector expansion has been the primary driver of load growth. This is expected to continue, though at a much slower pace. Additionally, we expect modest or no load growth for commercial and residential customers when compared with 2016 actual weather-adjusted deliveries. This is due primarily to energy efficiency of 1.5%, or 30 MWa. This resource of choice, as shown in PGE's recent integrated resource plans and the Northwest Power and Conservation Council's power plans, reduces load growth that would otherwise be expected to accompany population and economic expansion. Our prioritization of energy efficiency mirrors our customers' preferences and is reflected by a 15% reduction in average monthly residential energy use since 2000. We support will continue to support energy efficiency because it benefits our customers and our service area in many ways. For example, even while the price per kilowatt hour goes up, the average customer is using fewer kilowatt hours, leading to an associated savings both in terms of the amount of energy they consume as well as what it would cost to generate 30 aMW in alternative new generation. Figure 1 below shows that inflation-adjusted residential average bills were roughly the same in 2007 and 2016, with decreasing use per customer.

Figure 1
Residential Use and Bill 2007-2016



Q. Over the long term, does modest load growth create regulatory challenges?

A. Yes. Historically for PGE, as well as the industry as a whole, growth in retail loads and the associated net margins contributed to our ability to avoid filing GRCs for cost increases in the business. All else equal, and inclusive of our cost management efforts, this translated into fewer GRCs and longer periods between GRCs. In today's low retail load growth environment, we are faced with a need to increase customer prices to align forecast revenues with forecast costs on a more frequent basis to allow for the opportunity to earn a reasonable return and to maintain access to lower cost capital markets.

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

A. This case reflects the savings achieved through our continuous improvement efforts including some of the ongoing projects discussed above. As discussed in the next section, our use of continuous improvement cycles demonstrates our commitment to manage costs, streamline processes, learn from others, and create a continuous improvement culture at PGE that benefits customers through improved service and reduces long-term cost impacts.

IV. Continuous Improvement Cycle

Q. You mentioned continuous improvement. What is PGE doing to improve?

A. As discussed in detail in the last three GRCs (UE 262, UE 283, and UE 294), PGE conducts periodic benchmarking to identify areas for improvements and best practices. In addition to our benchmarking efforts, we also engage in Lean process reviews and business process analysis. In support of these reviews we implemented a Process Improvement program to pair education on process improvement with practical application through training and the implementation of improvement initiatives. These efforts continue to yield results and reinforce PGE's culture as one of continuous improvement.

Q. How does PGE hold business units accountable to these goals?

A. Accountability starts at the top. Each year we develop corporate scorecard metric goals that are focused on five key areas: 1) public and employee safety and health; 2) high customer value; 3) system reliability, including: high T&D reliability and generation plant availability, and reasonably priced power; 4) an engaged and valued workforce; and 5) financial performance. These areas of focus measure PGE's progress toward operational excellence and we monitor our status monthly. In addition, within each of these areas, accountability is assigned and cascades across the scorecards of managers throughout the organization to ensure alignment. This scorecard process allows management and individual contributors to understand their respective deliverables.

Q. Please explain PGE's continuous improvement cycle.

A. PGE's continuous improvement cycle is a regular and ongoing effort to increase our efficiency and effectiveness. Thus, after PGE business units have identified and implemented improvements, the benchmarking and improvement cycle begins again. We rotate through the organization, reviewing outcomes from measures already taken and identifying new efficiencies and best practices. PGE remains committed to its continuous improvement cycle and to becoming more efficient and effective in our day-to-day activities. The ultimate responsibility to continually improve is with all PGE officers and managers. These efforts are supported by PGE's Corporate Performance Management team. These efforts include benchmarking, which PGE uses to help each functional area understand how we compare to peer companies, identify best practices, determine areas to improve based on a business case, and implement our operational efficiency and effectiveness initiatives. These changes typically address improvements for people, processes and/or technology. PGE Exhibit 101 shows the departments currently conducting benchmarking and those scheduled for the next few years.

Q. How long will this benchmarking effort continue?

A. PGE's continuous improvement process is an ongoing effort with incremental savings or avoided costs expected over multiple years. By definition, continuous improvement cannot be a process that ends at a particular point in the future, so there are several business units in varying stages of the benchmarking process at any given time. Once a unit has completed the process, it can be expected to begin it again with a cycle that will last several years. The goal is to improve, by numerous measures that include quality of service and customer experience as well as cost. While we strive for cumulative overall savings and cost avoidance and intend to continue this process for the foreseeable future as part of PGE's Corporate Strategic Direction and Core Principles, it is not realistic to expect significant cost savings on a consistent, annual basis.

V. Other Elements of This Filing

Q. What other elements are included in this rate case?

A. Our case includes the following:

- PGE's participation in the Western EIM and the associated costs and benefits that create an overall benefit for PGE's customers, further discussed in PGE Exhibit 300;
- A request for an accounting order for pension expense to mitigate an increase that would otherwise occur due to changes in FASB accounting standards, further discussed in PGE Exhibit 400;
- An accounting order related to CET costs, as discussed in PGE Exhibit 900, to authorize:
  - The 2018 CET program development O&M costs to be booked to a regulatory asset and included in rate base, as applicable, along with all remaining balances from prior CET deferral vintages (similar to 2014-2016 CET deferral treatment)
  - The remaining balance of all the 2014-2018 deferrals to be amortized in base prices over ten years beginning in 2018
- A major maintenance accrual for the Colstrip power plant, similar to the accruals for the Port Westward 1, Coyote Springs, Port Westward 2, and Carty generating plants to levelize the major maintenance costs, further discussed in PGE Exhibit 700;
- A balancing account mechanism for major storms similar to that for major maintenance accruals as used for thermal generating plants, further discussed in PGE Exhibit 800;
- A forecasted capital structure of 50% equity and 50% debt to allow PGE to maintain our stable, investment grade credit rating, which will provide the financial strength

necessary to allow us access to capital markets, make ongoing investment in our system, and provide access to wholesale fuel and power markets;

- An authorized ROE of 9.75%, which is in the lower portion of the range recommended by our expert witness, Dr. Villadsen, in PGE Exhibit 1100. Dr. Villadsen's range is based on her sample using several methodologies. Her recommended point estimate is 10.15%, which is above the sample average because PGE has more risk than the average utility in the sample; and
- Increase the residential customer charge by $1.00 per month and increase the small commercial (Schedule 32) customer charge by $2.00 per month for both single and three phase service. The modest increase in the customer charge enables PGE to recover more of our fixed costs in the customer charges and directly reduces the volumetric charges. The increase balances the need for fixed cost recovery, with the principle that the volumetric energy prices provide a price signal for customers to implement energy efficiency measures.

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 with the opportunity to fund capital investments, meet its financial obligations, and provide an opportunity for our shareholders to receive a reasonable return on their investment.

Q. Are there other risks for changes to your requested price increase not currently included in the costs for this GRC filing?

A. Yes. State and federal tax policy changes have the potential to affect the cost to serve our customers. In turn, for any changes in the effective state or federal tax rate, we would need to assess the effect on our deferred taxes.

Oregon Ballot Measure 97 proposed a gross sales tax for businesses with revenues over $25 million. That ballot measure failed to pass with Oregon voters in November 2016. However, the state continues to face a budget deficit that the proponents of the ballot measure, including the governor, and others seek to address during the 2017 legislative session. PGE and its customers could be affected by a legislative solution. Had Ballot Measure 97 passed, it would have been necessary to collect as much as 4% of PGE's retail revenue from customers to pay the additional tax expense.

It's uncertain whether a legislative solution will be reached, and how or if it will affect PGE and its customers. A solution that increases PGE's Oregon tax expense will necessitate cost recovery.

There are also discussions at the federal level about changes to federal tax policy and we are monitoring those discussions. We have not included these potential changes to federal or state tax policy in this filing, but if they occur during this case we will update our filing to reflect the changes.

VI. Structure of PGE's Filing

Q. How is PGE presenting this case?

A. PGE is presenting the following direct testimony:

- In Exhibit 200, Alex Tooman, Project Manager, and Rebecca Brown, Senior Analyst, summarize the overall 2018 test year revenue requirement, comparing the request with the 2016 actuals. This testimony also discusses PGE's rate base at year end 2017, plus associated depreciation and amortization, and unbundled results.
- In Exhibit 300, Managers Mike Niman and Terri Peschka, and Aaron Rodehorst, Senior Analyst, provide the initial forecast of PGE's Net Variable Power Costs (NVPC) and discuss updates to parameters and modeling changes, comparing the forecast with the final 2017 NVPC forecast.
- In Exhibit 400, Anne Mersereau, Vice President, Human Resources, Diversity & Inclusion, and Jardon Jaramillo, previously the Director of Compensation and Benefits and currently Controller and Assistant Treasurer, present PGE's compensation costs for the 2018 test year, efficiency gains, changes to compensation policies and plans, and proposed pension cost recovery.
- In Exhibit 500, Cam Henderson, Vice President of Information Technology (IT) and Chief Information Officer (CI0); Behzad Hosseini, Director of the Office of CIO; and Travis Anderson, Information Security Director and Manager of IT Risk Management, explain PGE's costs and cost drivers related to information technology and cyber security.
- In Exhibit 600, Jim Lobdell, Senior Vice President, Finance, Chief Financial Officer and Treasurer; and Alex Tooman, Project Manager, explain PGE's costs and cost

drivers related to corporate support operations including business continuity and emergency management, safety, insurance, research and development, and environmental services.

- In Exhibit 700, Bradley Jenkins, Vice President of Power Supply Generation, and Aaron Rodehorst, Senior Analyst, support O&M costs associated with PGE's power supply resources. This joint testimony also discusses recent plant performance and PGE's proposal to create a major maintenance accrual for the Colstrip generating plant.
- In Exhibit 800, Bill Nicholson, Senior Vice President of Customer Service, Transmission and Distribution, and Larry Bekkedahl, Vice President of Transmission and Distribution, explain PGE's 2018 test year transmission and distribution O&M expenses, capital improvement efforts, and how they support PGE's goal of operational excellence.
- In Exhibit 900, Kristin Stathis, Vice President of Customer Service Operations, and Carol Dillin, Vice President of Customer Strategies and Business Development explain customer service O&M costs for the 2018 test year. They also provide a detail update of the CET program and describe the initiatives that support the customer experience.
- In Exhibit 1000, Patrick Hager, Manager of Regulatory Affairs, and Chris Liddle, Corporate Finance and Investor Relations Manager & Assistant Treasurer, recommend PGE's cost of capital and capital structure for the 2018 test year.
- In Exhibit 1100, Bente Villadsen, economist and principal at The Brattle Group, estimates PGE's required ROE and describes the supporting analyses.

- In Exhibit 1200, Sarah Dammen, Manager of Financial Forecasting and Economic Analysis, and Amber Riter, Economist and Lead Load Forecast Analyst, provide the initial load forecast and explain the process and method in forecasting the 2018 test year load.
- In Exhibit 1300, Marc Cody and Robert Macfarlane, Senior Analysts, describe marginal cost studies for generation, transmission, distribution, and customer service.
- In Exhibit 1400, Marc Cody and Robert Macfarlane, Senior Analysts, describe how the proposed tariff changes recover PGE's 2018 revenue requirement to achieve fair, just and reasonable prices for our customers and price changes to various supplemental schedules.

VII. Qualifications

Q. Mr. Piro, please describe your educational background and experience.

A. I received a Bachelor of Science degree from Oregon State University in Civil Engineering in 1974 with an emphasis in Structural Engineering. In addition, I have taken postgraduate courses in engineering, accounting, economics, and ratemaking. I am a registered Professional Engineer in Civil Engineering in the State of California (Registration No. 28174). I joined PGE in 1980 and have held various positions in Generation Engineering, Economic Regulation, Financial Analysis and Forecasting, Power Contracts, Economic Analysis, Planning Support, Analysis and Forecasting, and Business Development. I was elected Vice President of Business Development in 1998 and then became Chief Financial Officer and Treasurer on November 1, 2000. I was then named Senior Vice President, Finance, Chief Financial Officer and Treasurer on May 1, 2001, and later became Executive Vice President, Finance, Chief Financial Officer and Treasurer effective July 25, 2002. I entered my current position as President and Chief Executive Officer effective January 1, 2009.

I also serve on several community and business boards including Greater Portland Inc., the PGE Foundation, the Oregon Business Council, the All Hands Raised Leadership Council and the Edison Electric Institute. I am also the Chair of the Oregon STEM Investment Council and a member of the Oregon Global Warming Commission.

Q. Mr. Lobdell, please describe your qualifications.

A. I received a Bachelor of Science degree from the University of Oregon in 1984. Since joining PGE as a business analyst in 1984 I have held a variety of positions at PGE and its affiliates. I was senior director of Business Development, director of Internal Audit Services and manager of Financial Risk Management & Pricing, where I provided financial risk management for PGE's wholesale electric and natural gas portfolios. I then served as vice president of Power Operations and vice president of Risk Management, Reporting, Controls & Credit. In 2004, I was named vice president of Power Operations and Resource Strategy. I entered my current position as Senior Vice President, Finance, Chief Financial Officer, and Treasurer in March 2013.

I am a member of the FM Global Advisory Committee, Treasurer of the PGE Foundation, advisory member of the University of Oregon Portland Council, and board member of the ALS Association of Oregon and SW Washington.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
101	Projected Benchmarking Schedule

Projected Benchmarking Schedule

Next Benchmark	Function	Previous Benchmark	Data Year Analyzed	Cycle (Yrs)
2018	Customer Service	2012	2011	6
	Transmission & Distribution	2011	2010	7
2019	Information Technology	2015	2014	4
	Finance	2014	2013	5

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Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Alex Tooman, Ph.D.
Rebecca Brown

February 28, 2017

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I. Introduction

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

A. My name is Alex Tooman. I am a project manager for PGE. I am responsible for the development of PGE's revenue requirement forecast and other regulatory analysis.

My name is Rebecca Brown. I am a senior analyst assisting Alex Tooman in the development of the revenue requirement.

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 2018 revenue requirement for base business of $1,883.3 million.

Q. What increase in revenue requirement does PGE request beginning January 1, 2018?

A. PGE requests a base business increase of $99.9 million or 5.6% effective January 1, 2018. This increase is relative to the revenues we expect based on 2016 prices, approved in UE 294. This revenue requirement will allow PGE an opportunity to earn a 7.46% rate of return that includes a 9.75% return on average common equity (ROE) of 50% in 2018. PGE Exhibit 201, columns 1 through 3, summarizes the development of PGE's 2018 revenue requirement for base business. In addition to presenting this integrated (bundled) revenue requirement, we also present and discuss our unbundled revenue requirement in Section IX.

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

A. As described in PGE Exhibit 100, to reduce the price impact on customers, we adjusted the revenue requirement by:

1. Reducing our request related to incentive compensation costs;

2. Removing 50% of certain layers of Directors & Officers (D&O) insurance;
3. Requesting a return on equity at the lower portion of the range supported by PGE's expert witness.

A. PGE Result if No Price Increase is Authorized

Q. In the absence of a price increase, what is PGE's expected regulated ROE for 2018?

A. Without a price increase, we would expect PGE's ROE to be approximately 7.2% in 2018, lower than the authorized ROE of 9.6%.

B. Structure of the Case

Q. Please summarize PGE's 2018 revenue requirement.

A. Table 1 below summarizes PGE's 2018 revenue requirement by major category and provides a comparison to the results of UE 294. We also list the PGE testimony that addresses each specific cost category.

Table 1

Revenue Requirement Summary
($ in millions)

Rev Req Category	UE 294 Approved	2018 Budget	Exhibit	No.
Sales to Consumers	$1,864.6	$1,883.3	Rev Req	200
Other Revenue	$ 26.6	$ 25.8	Rev Req	200
NVPC	$ 531.6	$ 353.6	Power Costs	300
Production O&M	$ 156.1	$ 159.8	Production	700
Transmission O&M	$ 14.3	$ 14.3	T&D	800
Distribution O&M	$ 94.5	$ 120.2	T&D	800
Customer Service	$ 79.3	$ 82.3	Customer Svc.	900
A&G	$ 151.4	$ 172.1	Corp. Support	600
Depr. & Amort.	$ 330.5	$ 377.3	Rev Req	200
Other Taxes	$ 126.1	$ 127.2	Rev Req	200
Income Taxes	$ 74.1	$ 159.7	Rev Req	200
Operating Income*	**$ 333.4**	**$ 342.7**		
Return on Equity	9.6%	9.75%	Return on Equity	1100

** 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 Exhibits 1000 and 1100.

Q. How did you develop the 2018 revenue requirement?

A. We developed the revenue requirement based on PGE's 2017 budgets, which were originally based on UE 294 prices as authorized by Commission Order No. 15-356. The 2017 budgets were escalated for inflation to 2018 and adjusted for known and measureable changes.

Q. What rates did you use to escalate the 2017 budget to 2018 test year?

A. We applied the following escalation rates to the 2017 budget:

- 3.10% average rate for all labor (at applicable effective dates[1]).
- 3.11% for outside services (cost elements [CE] 1502, 1602, 2200, and 2300), effective January 1.
- 1.66% for direct materials (CE 2101 and 2110), effective January 1.
- 2.39% for employee business expense (CE 2400 and 2701), effective January 1.

Q. What are the sources of these escalation rates?

A. For outside services, direct materials and employee business expense, we use escalation rates from the Global Insights, Long-term Forecast dated August 2016. Wage escalation is based on the forecast of compensation costs described in PGE Exhibit 400.

Q. What comparison with the 2018 test year costs does PGE make in the testimonies generally?

[1] March 1 for bargaining employees and April 1 for non-bargaining employees.

A. We compare our forecast of 2018 test year costs to 2016 actuals. We do this because 2016 represents PGE's most recent full year with actual results. The changes between 2016 and 2018 in this filing will be analyzed on an average annual basis.

Q. Did you adjust PGE's 2018 revenue requirement to reflect previous pricing decisions and other regulatory policies?

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

Table 2
Regulatory Adjustments
($ in millions)

Category	O&M	Rate Base
Retail Services	$(0.1)	$(0.9)
Charitable Contributions	$(1.9)	
State & Federal Lobbying	$(1.0)	
MDCP	$(4.7)	
SERP	$(1.4)	
Image Advertising	$(0.7)	
Total Adjustments	**$(9.8)**	**$(0.9)**

Q. Please explain these regulatory adjustments.

A. Following is a brief summary:

- Retail services: removed the revenue requirement related to amounts allocated to PGE's retail operations;
- Charitable contributions: excluded the entire $1.9 million from cost of service;
- State and federal lobbying: excluded the entire $1.0 million from cost of service;
- Managers' Deferred Compensation Plan (MDCP): removed the entire $4.7 million from cost of service;
- Supplemental Executive Retirement Plan (SERP): removed the entire $1.4 million from cost of service; and
- Corporate image advertising: removed the entire $0.7 million from cost of service.

II. Other Revenue

Q. What is PGE's 2018 forecast of Other Revenue?

A. PGE forecasts 2018 Other Revenue of $25.8 million. This compares to 2016 Other Revenue of $26.7 million. The decrease is primarily attributable to joint pole revenue, which declines from 2016 actuals because:

- 2016 actuals reflect approximately $1.2 million in revenue for a short-term, high-speed fiber deployment project that did not continue beyond 2016.
- There is an overall decline in PGE's annual pole attachment rental rate.

Q. What are the sources of Other Revenue?

A. The primary sources of Other Revenue are rent of electric property, transmission revenue, joint-pole revenue, steam sales revenue, and ancillary service revenue. 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 2018 test year?

A. Yes. We adjusted the 2018 forecast of transmission revenues received from Energy Service Suppliers (ESS). The adjusted amounts reflect PGE's current Open Access Transmission Tariff rate and the forecasted ESS activity for 2018.

III. Depreciation

Q. What was used for the 2018 test year book depreciation expense?

A. Normalization rules in the Internal Revenue Code, Section 168(i)(9) require consistency in the calculation of four items for ratemaking purposes. Two of the four items are tax expense and book depreciation expense. The other two items are in rate base: accumulated book depreciation and accumulated deferred income taxes. Because, PGE established its rate base as of December 31, 2017, we used 2017 depreciation in the calculation of all four items.

Q. Does 2017 depreciation accurately reflect the 2018 expense?

A. By itself, no. Because 2017 depreciation will only reflect partial year depreciation for all 2017 plant closings, 2017 depreciation will be less than 2018 depreciation, which will reflect a full year of depreciation for those same assets (assuming no additional plant closings in 2018). In order to adjust for this effect, PGE annualized the 2017 depreciation expense for 2017 plant closings. We then reduced that amount to account for the fact that PGE's declining balance method results in a 2018 depreciation expense that would not be as high as that calculated with the full annualization effect. The net result is that the test year depreciation is based on 2017 expense (to meet IRS normalization requirements) but has an adjusted annualization so that PGE does not under-collect or over-collect depreciation expense relative to expected 2018 depreciation expense. As noted above, the expected 2018 depreciation expense does not reflect any 2018 closings. For simplicity, we refer to the test year depreciation as 2018 depreciation expense.

Q. What is PGE's estimate for 2018 depreciation expense?

A. We estimate $317.4 million in depreciation expense for 2018. PGE Exhibit 203 summarizes the 2018 depreciation expense by plant type and provides a comparison to 2016 actuals.

Q. Is PGE proposing a new depreciation study as part of this rate case?

A. Yes. PGE filed the new depreciation study on December 23, 2016. It is docketed as UM 1809.

Q. What is the difference between the previous depreciation study (Docket No. UM 1679) estimate for 2017 depreciation expense and the current depreciation study estimate (Docket No. UM 1809)?

A. The methodology proposed in the current depreciation study leads to a $2.2 million increase in depreciation expense in 2017.

Q. How does PGE's 2018 depreciation expense forecast compare to 2016 actuals?

A. After adjustments, total forecasted depreciation for 2018 reflects a $40.1million increase over 2016 actuals.

Q. What are the primary drivers for the increase?

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

- $4.4 million for the Colstrip generation plant to reflect the change of depreciable life from 2042 to 2030 as specified in Oregon Senate Bill 1547, Section 1.
- $6.8 million in the Carty generation plant, which had only partial year depreciation in 2016 but a full year in 2018. Customer prices, however, already reflect the full year of Carty 2016 depreciation expense in accordance with Commission Order No, 15-356.
- $4.0 million in other thermal generating plants.
- $4.7 million in wind and hydro generation resources.
- $6.4 million in distribution.
- $3.5 million in general plant.

IV. Amortization

Q. What is amortization?

A. Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life. Amortization relates to intangible assets, such as computer software and regulatory assets. As with depreciation expense, the unamortized balance of the associated assets generally appears in rate base and earns a return at the allowed rate. Because amortization is also subject to tax normalization principles, we calculated the 2018 test year amortization expense based on the adjusted annualized 2017 amortization similar to depreciation.

Q. Please summarize PGE's 2018 amortization expense.

A. PGE Exhibit 204 details the total 2018 amortization expense of $68.3 million, which we summarize in Table 3 below.

Table 3
Amortization
($ in millions)

Amortization Item:	2016 Actuals	2018 Forecast
Software Amortization	$ 35.7	$ 47.0
Other Intangible Amortization	$ 8.4	$ 9.3
Trojan Decommissioning	$ 3.5	$ 3.5
Trojan Fuel Settlement	$ (16.3)	$ 0.0
Other Reg Debit Amortization	$ 9.4	$ 8.8
Other Reg Credit Amortization	$ 0.2	$ (0.2)
Total Amortization*	**$ 40.8**	**$ 68.3**

***** *May not sum due to rounding*

Q. Please explain the amortization of software included in PGE's 2018 amortization expense.

A. Total software amortization is approximately $47.0 million. This cost relates to capitalized software, which is typically amortized over a 5-year period. The exception to this period is the 2020 Vision program (including the Financial System replacement project, Maximo mobile scheduling, Outage Management System, Graphic Work Design, and Geographic Information System), which is amortized over a 10-year period.

Q. Why is software amortization $11.3 million higher in 2018?

A. The increase is due to the software investment that closed to Plant in Service during 2016, which results in partial year amortization in 2016 and full year amortization in 2018, as well as additional software investment in 2017. The larger software projects closing in 2016 and 2017 include the Energy Trading & Risk Management Solution, software upgrades to move customers to lower cost self-service options (Web Fitness-Remove Self Service Barriers), Knowledge Management & Governance Software for Customer Service Operations, and software for hosting the Western Energy Imbalance Market (discussed in PGE Exhibit 300, Section III, part C).

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.

V. Income Taxes, Taxes Other Than Income, and Fees

A. Income Taxes

Q. What is PGE's 2018 estimate of income taxes?

A. PGE's 2018 test period income tax expense forecast is $159.7 million. PGE Exhibit 205 details the test year calculations of income tax expense and provides a comparison to previously authorized 2016 income tax assumptions. This compares to the 2016 utility income tax expense of $74.1 million based on prices approved by Commission Order No. 15-356. The increase in 2018 test year income tax expense compared to current prices reflects: 1) an increase of pre-tax book income; and 2) federal production tax credits (PTC) being treated as a variable, rather than fixed, component of PGE's forecast, consistent with the provisions of Oregon Senate Bill 1547, Section 18b.

Q. Is the change in PTC treatment new for 2018?

A. No. PGE first implemented this change in Docket No. UE 308, PGE's 2017 Net Variable Power Cost filing, which was subsequently approved by Commission Order No. 16-419.

Q. What method did you use to establish estimated income tax expense for the 2018 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, since PGE's operations consist of nearly 100% regulated utility activity, this method also conforms to ORS 757.269, which specifies how income taxes are treated for developing retail prices.

Q. Are any state and federal tax credits included in your estimate of income tax expense for 2018?

A. No. As discussed above, federal PTCs are now reflected as part of PGE's net variable power costs. Additionally, all of PGE's state tax credits have been utilized and there are none currently forecasted for 2018.

B. Taxes Other Than Income and Fees

Q. What is PGE's 2018 estimate of Taxes Other Than Income and Fees?

A. As shown in PGE Exhibit 206, total Taxes Other Than Income are $127.2 million for 2018. This compares to 2016 actual costs of $118.2 million. The primary individual sources of increased costs from 2016 actuals to the 2018 test year are:

- Franchise Fees: from $43.1 million to $47.9 million; and
- Payroll Taxes: from $13.5 million to $16.1 million.

1. Franchise Fees

Q. Why have franchise fees increased from 2016 to the 2018 test year?

A. PGE updated the franchise fee rate to reflect the three-year average of 2014-2016 actuals. Although the franchise fee rate dropped slightly from 2.547% (UE 294) to 2.545%, overall, franchise fees increase because PGE's requested revenue requirement increases.

2. Payroll Taxes

Q. How does PGE estimate payroll taxes?

A. PGE estimates payroll taxes by applying an approximate 12.2% payroll tax rate to total wages and salaries. We allocate a portion of payroll tax cost to capital consistent with the allocation of overall capitalized wages and salaries.

Q. Why have payroll taxes increased from 2016 to the 2018 test year?

A. Payroll taxes increase as wages and salaries grow between those years as described in PGE Exhibit 400.

3. 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 Beaver plant). 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 weighed 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 1st of each year.

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

A. Yes. Similar to prior years, PGE has included tax savings related to Strategic Investment Program (SIP) property tax abatement agreements for Biglow Canyon, Port Westward II, and Carty.

Q. What is PGE's forecast for 2018 property taxes?

A. PGE has forecast approximately $60.7 million of 2018 property taxes compared to 2016 actuals of $59.2 million. The increase is primarily a result of the Carty plant being placed into service midway through 2016, along with other increases in plant in service.

VI. Rate Base

Q. What is PGE's 2018 rate base and what does it include?

A. PGE is using year-end 2017 rate base to preclude assets that are not in service prior to January 1, 2018, when base prices go into effect. As of December 31, 2017, PGE is expecting rate base to be approximately $4594.1 million. PGE Exhibit 207 provides the details of the 2017 rate base, which includes PGE's investment in plant in service, net of accumulated depreciation, and accumulated deferred income taxes (ADIT)[2]. In addition, the rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's 2017 rate base compare to amounts approved in UE 294?

A. PGE Exhibit 208 shows that the rate base approved in UE 294 is $4,440.2 million and that PGE's 2017 rate base reflects an increase of $153.9 million. The increase is primarily attributable to the growth in distribution plant in service as discussed in PGE Exhibit 800.

Q. Did you include the prepaid pension asset in rate base?

A. No. Based on Commission Order No. 15-226 (Docket No. UM 1633) we excluded the prepaid pension asset and the associated deferred tax liability from PGE's rate base.

Q. What is the working cash total added to rate base in this filing?

A. Applying the 3.628% working cash factor to total forecasted operating expenses in 2018 of $1,566.5 million yields the working cash total in rate base of approximately $56.8 million. This amount is shown in PGE Exhibit 201.

[2] ADIT is also calculated based on year-end 2017 amounts, consistent with IRS Normalization principles.

VII. Carty Update

Q. Please summarize the ratemaking relief PGE sought for Carty in Docket No. UE 294.

A. In UE 294, PGE requested that prices recovering Carty's net revenue requirement become effective shortly after a PGE officer provided an attestation that Carty was placed in service.

Q. Did Commission Staff analyze the prudence of PGE's actions related to Carty?

A. Yes. Staff analyzed the prudence of PGE's actions related to Carty from two perspectives. First, Staff analyzed the consistency of Carty with previous integrated resource plans (IRPs) and request for proposals (RFPs). Second, Staff analyzed the prudence of Carty as of the date when the Company decided to proceed with the project.[3]

Q. What was the outcome of UE 294, with respect to Carty?

A. On November 3, 2015, the Commission issued Order No. 15-356 approving settlements reached in UE 294. With respect to Carty, the approved settlements stipulate PGE's decision to construct Carty was prudent. The approved settlements also identify the conditions for which Carty's prudently incurred costs and benefits would be included in customer prices when Carty begins providing service to customers. The conditions include:[4]

> i. For determining rates in this docket only, the gross plant for Carty, including the Grassland Switchyard, will be $514 million… If Carty capital costs are higher than the designated amount, PGE may not recover those costs through the Carty tariff rider. However, PGE will not be bound to the original $514 million estimate in subsequent rate proceedings. If PGE seeks to recover any additional amounts in a subsequent general rate filing, PGE must demonstrate the prudence of such additional costs.
>
> ii. PGE will file an attestation by an officer when the Carty plant is placed in service.

[3] See UE 294 Staff Exhibit 1700, page 6.
[4] Commission Order No. 15-356, Appendix A, pages 4 and 5.

iii. If the Carty Generating Station is not completed and in service by July 31, 2016, PGE will need to file a new ratemaking request seeking the inclusion of the Carty costs in rates, inclusive of Grassland Switchyard.

Q. Did PGE place Carty into service by July 31, 2016?

A. Yes. PGE placed Carty into service on July 29, 2016.

Q. Are Carty capital costs higher than $514 million in PGE's 2017 year-end rate base?

A. Yes. The Carty capital costs are approximately $521.7 million in PGE's year-end 2017 rate base.

Q. Why are the Carty capital costs higher than $514 million?

A. Because PGE did not place Carty into service until July 29, 2016, PGE accrued approximately two months of additional financing (i.e., AFDC) on the capital costs that were determined to be prudent through Commission Order No. 15-356. The $514 million capital cost forecast used by PGE in UE 294 assumed that Carty would be in-service by mid-May 2016. Thus, the additional costs included in this case represent timing only and are fully consistent with the construction costs previously approved.

Q. What are the overall construction costs to build the Carty facility?

A. PGE expects construction costs to total between $635 and $640 million, excluding certain lien claims totaling $17 million that PGE is challenging.

Q. Does this rate case include the additional construction costs associated with Carty?

A. No. As explained earlier, PGE included only the original cost estimate of $514 million, adjusted for AFDC for the time value difference between the actual online date in July 2016 and the originally expected online date in May 2016.

Q. Is PGE continuing to diligently pursue payment from Liberty Mutual and Zurich American Insurance Company pursuant to a performance bond as described in PGE's SEC financial statement disclosures?

A. Yes. For a more complete update on the status of these legal matters, see PGE's 2016 10-K (Part II, Item 8, Note 17).

VIII. Customer Engagement Transformation (CET)

Q. Please provide an update on PGE's Customer Engagement Transformation (CET) project.

A. PGE continues to work toward the completion of CET, which has been a multi-year program consisting of 24 projects and culminating in 2018 with the replacement of two legacy customer systems: Customer Information System and Meter Data Management System.

Q. Are you including the revenue requirement for the systems closing in 2018 in your request?

A. No. PGE is not including the 2018 CET projects in customer prices at this time. Capital costs for CET will be presented in a future rate making proceeding. PGE Exhibit 900 provides a detailed update of CET.

IX. Unbundling

Q. Have you unbundled the 2018 revenue requirement pursuant to OAR 860-038-0200?

A. Yes. PGE Exhibit 209 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 2018.

Table 4
Unbundled Revenue Requirement
($ in millions)

Production	$1,090.7
Transmission	$ 28.5
Distribution	$ 635.8
Ancillary	$ 4.9
Metering	$ 8.4
Billing	$ 63.0
Other Consumer Services	$ 52.0
Total*	**$1,883.3**

** 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 columns 1 through 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).

Q. How did you unbundle PGE's 2018 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 costs is administrative and general (A&G), which we allocated to the functional areas based on labor dollars for those areas. Other costs, such as property taxes, and payroll taxes, relate to factors such as net plant or labor. We allocated these costs based on the respective share of those factors per functional area 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" – see 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) based on that labor. 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, accumulated deferred taxes, and accumulated investment tax credits; 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, transformers, and service drops). Some general and intangible plant was directly assigned, but the majority of these categories consist of many smaller assets without a clear functional attribute so we allocated them based on labor.

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 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.

X. Qualifications

Q. Mr. 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. Ms. Brown, please state your educational background?

A. I received a Bachelor of Science degree in Accounting from the University of Nevada-Reno and a Master of Business Administration with an emphasis in Finance from the University of Wyoming. I am a Certified Public Accountant. I have worked at three state commissions (Wyoming, Texas and Oregon) totaling 12 years of direct regulatory experience. I also worked at PacifiCorp for nearly three years in Corporate Accounting and have been with PGE since 2007 (in the Rates and Regulatory Affairs department for over seven years), totaling over 25 years of experience.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
201	2018 Results of Operations Summary
202	Summary of Other Revenue Sources
203	Summary of Depreciation Expense by Plant Type
204	Summary of Amortization Expense
205	Summary of Income Taxes
206	Summary of Taxes Other Than Income
207	Summary of Rate Base
208	Reasons for Changes in Rate Base since 2016 (UE 294)
209	Unbundled Results of Operations Summary

PGE Exhibit 201
2018 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	Base Business		5.60%
	2018 Results at 2016* Base Rates	Change for Reasonable Return	2018 Results After Change for Reasonable Return
	(1)	(2)	(3)
Operating Revenues			
Sales to Consumers (Rev. Req.)	1,783,435	99,897	1,883,332
Sales for Resale	-	-	-
Other Operating Revenues	25,841	-	25,841
Total Operating Revenues	1,809,276	99,897	1,909,173
Operation & Maintenance			
Net Variable Power Cost	353,586	-	353,586
Operations O&M	294,319	-	294,319
Support O&M	253,554	744	254,298
Total Operation & Maintenance	901,459	744	902,203
Depreciation & Amortization	377,278	-	377,278
Other Taxes / Franchise Fee	124,683	2,543	127,226
Income Taxes	121,190	38,559	159,749
Total Oper. Expenses & Taxes	1,524,610	41,846	1,566,457
Utility Operating Income	284,665	58,051	342,716
Rate of Return	6.198%		7.460%
Return on Equity	7.227%		9.750%

* 2016 Rates per approved UE 294

Rate Base			
Plant in Service	9,879,272	-	9,879,272
Accumulated Depreciation	(4,735,925)	-	(4,735,925)
Accumulated Def. Income Taxes	(634,410)	-	(634,410)
Accumulated Def. Inv. Tax Credit	-	-	-
Net Utility Plant	4,508,938	-	4,508,938
Misc Deferred Debits	20,863	-	20,863
Operating Materials & Fuel	80,737	-	80,737
Misc. Deferred Credits	(73,318)	-	(73,318)
Working Cash	55,314	1,518	56,833
Total Rate Base	4,592,534	1,518	4,594,052

PGE Exhibit 201
2018 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	Base Business		5.60%
	2018 Results at 2016* Base Rates	Change for Reasonable Return	2018 Results After Change for Reasonable Return
	(1)	(2)	(3)
Income Tax Calculations			
Book Revenues	1,809,276	99,897	1,909,173
Book Expenses	1,403,420	3,287	1,406,707
Interest Rate Base @ Weighted Cost of Debt	118,717	39	118,756
Production Deduction	9,000	-	9,000
Permanent Sch M Differences	(24,268)	-	(24,268)
Temporary Sch M Differences	45,835	-	45,835
State Taxable Income	256,572	96,571	353,143
State Income Tax	20,136	7,322	27,459
Federal Taxable Income	236,436	89,249	325,684
Fed Income Tax	82,752	31,237	113,989
Deferred Taxes	18,301	-	18,301
Federal Tax Credits	-	-	-
Total Income Tax	121,190	38,559	159,749

PGE Exhibit 201
General Rate Case - 2018 Test Year
Capital Structure / Revenue Sensitive Costs
(000s)

Capital Structure:	**Amount**	**Share**	**Cost**	**Weighted**
Common Equity	N/A	50.00%	9.750%	4.875%
Preferred	N/A	0.00%	0.00%	0.000%
Long-Term Debt	N/A	50.00%	5.170%	2.585%
Total	N/A	100.00%		**7.460%**

Revenue Sensitive Costs:	
Revenues	100.0000%
OPUC Fees	0.3750%
Franchise Fees	2.5455%
O&M Uncollectibles	0.3700%
State Taxable Income	96.7095%
State Tax @ 7.212%	7.3328%
Federal Taxable Inc.	89.3768%
Federal Tax @ 35%	31.2819%
Total Income Taxes	**38.6146%**
Total Rev. Sensitive Costs	**41.9051%**
Utility Operating Income	58.0949%
Net To Gross Factor	**1.721321**
RSC Gross-Up Factor	1.0340

State Income Tax:

	Appor	Rate	Weighted
Montana	2.91%	6.75%	0.197%
Washington	0.00%	0.00%	0.000%
California	1.34%	8.84%	0.119%
Oregon	95.62%	7.60%	7.267%
State			7.582%
Composite Tax Rate:			**39.928%**

Check:	Fed Tax	35.00%
	State Tax	7.582%
	Tax Shield	-2.65%
	Composite	39.928%

Working Cash Factor	3.628%

PGE Exhibit 202
Other Revenue Detail
2014 - 2018 Test Year

Account	Description	2014 Actuals	2015 Actuals	2016 Actuals	2017 Budget	2018 Test Year
4470003	SalesfrResale-IntertiePGEtoPGE	(3,069,994)	(4,816,292)	(5,936,823)	(5,934,000)	(5,934,000)
4500001	Forefeited Discounts	(3,092,995)	(3,019,107)	(2,994,617)	(2,900,000)	(2,900,000)
4510001	Miscellaneous Service Revenues	(1,716,285)	(1,796,073)	(1,852,377)	(1,905,392)	(2,338,315)
4530001	Sales of Water & Water Power	27,627	22,164	24,166	-	-
4540001	Rent From Electric Property	(1,302,935)	(1,043,393)	(1,025,319)	(1,216,905)	(1,217,728)
4540002	RentFrElecProperty-Joint Pole	(6,180,231)	(6,564,797)	(7,679,162)	(6,234,855)	(6,279,394)
4560001	Other Electric Revenues	(4,538,748)	(3,487,297)	(3,648,451)	(2,971,527)	(2,973,166)
4560002	OthElecRev-RegulatoryDeferRev	-	-	-	-	-
4560003	OthElecRev-FishWildlifeRecrOps	(15,168)	(19,493)	(12,386)	-	(16,002)
4560004	OthElecRev-SSHG	(283,870)	(239,360)	(69,475)	(193,177)	(277,087)
4560005	OthElecRev-Utility Non-Kwh	(1,566)	(2,657)	(2,478)	-	-
4560012	OthElecRev-Steam Sales	(2,494,638)	(2,555,480)	(1,480,085)	(1,684,211)	(1,684,211)
4561001	TransRevOthers-Non-Intertie	(2,344,157)	(2,971,892)	(2,899,444)	(3,034,800)	(3,110,945)
4561002	TransRevOthers-Intertie	(5,683,073)	(5,285,337)	(5,080,702)	(5,044,000)	(5,044,000)
5660002	TransOp-MiscExp-IntertieWhePGE	3,069,994	4,816,292	5,936,823	5,934,000	5,934,000
Total		(27,626,038)	(26,962,722)	(26,720,329)	(25,184,867)	(25,840,848)

PGE Exhibit 203

Depreciation Detail ($000s)

2014 - 2017 Test Year

	(1)	(2)	(3)	(4)	(5)
Property Group	**2014 Actuals**	**2015 Actuals**	**2016 Actuals**	**2017 Forecast**	**2017 Forecast used for 2018 Test Year**
Boardman	26,816	29,642	30,023	30,363	30,363
Colstrip	5,041	5,308	5,161	9,546	9,546
Beaver	3,668	4,644	5,573	7,483	7,483
Biglow Canyon	35,015	33,490	32,095	32,830	32,830
Carty			6,696	13,489	13,489
Coyote Springs	4,792	5,136	4,919	4,743	4,743
DSG	548	332	340	344	344
Port Westward	6,520	8,647	8,668	8,645	8,645
Port Westward 2	21	8,160	8,042	10,019	10,019
Solar		42	79	429	429
Tucannon	718	17,316	16,761	18,090	18,090
Hydro	11,847	15,806	18,319	20,995	20,995
Transmission	9,819	9,078	10,025	12,744	12,744
Distribution	118,604	97,611	101,051	107,446	107,446
General Plant	25,919	33,915	35,430	38,884	38,884
Total	**249,328**	**269,127**	**283,182**	**316,050**	**316,050**
Remove Boardman Decommissioning	(3,395)	(5,877)	(5,877)	(5,877)	(5,877)
Asset retirement depreciation - 4031001				7,325	7,325
Retail Adjustment				(74)	(74)
Adjusted Total	**245,933**	**263,250**	**277,305**	**317,424**	**317,424**

Notes:

(1) 2014 Boardman depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study.
2014 depreciation excludes coal car depreciation of $261 and vehicle depreciation of $4,214.

(2) 2015 Boardman depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study with additional 15% ownership of non-coal handling assets, bringing PGE total share to 80%.
2015 depreciation excludes coal car depreciation of $261 and vehicle depreciation of $3,516 or $3,637

(3) 2016 Boardman depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study with additional 10% ownership and retention program, bringing PGE total share to 90%.
2016 depreciation excludes coal car depreciation of $318 and vehicle depreciation of $4,781.
2016 Sunway becomes part of base business

(4) 2017 Boardman forecasted depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study.
2017 forecasted depreciation excludes coal car depreciation of $266 and vehicle depreciation of $4,304.

PGE Exhibit 204
Amortization Detail
2014 - 2018 Test Year
($000)

Item	FERC Account	AWO	(1) 2014 Actuals	(2) 2015 Actuals	(3) 2016 Actuals	(4) 2017 Forecast	(5) 2017 Forecast used for 2018 Test Year
Software Amortization (Intangible)	404.0		22,237	30,053	35,668	46,999	46,999
Other Intangible Plant (Includes Hydro Relicensing)	404.0		3,163	8,312	8,430	9,294	9,294
Trojan Decommissioning	407.0	7000000045	3,500	3,500	3,500	3,500	3,500
Trojan Spent fuel Settlement	407.0	3000000786	0	(16,800)	(16,340)	(17,312)	0
Independant Evaluator Deferral	407.3		20	547	35	0	0
Colstrip Common FERC Adjustment	407.3	7000000107	322	322	322	107	107
Schedule 110 EE Asset Balancing Acccount	407.3	7000000124	921	902	884	942	942
AMI Project Office Costs	407.3		0	0	0	0	0
Fit Pilot Program	407.3	7000002001	5,051	6,248	7,975	7,740	7,740
Regulatory Deferral Amortz	407.3	7000010741	15,978	18,959	155	0	0
Residual Balance	407.3		0	0	0	0	0
Regulatory Deferral (capital Deferral)	407.4	7000010741	13	0	0	0	0
2011 Local 408/MCBIT Deferral	407.4	3000000135	(180)	168	515	(440)	(200)
Int Income PES Note	407.4	7000000319	0	0	0	0	0
ISFSI Tax Credits-Used	407.4	7000000324	0	(5,290)	(300)	0	0
SunWay 3	407.4	7000000727	(45)	(45)	(45)	0	0
			50,979	46,875	40,798	50,831	68,383
Allocated to retail							(47)
Total Amortization			**50,979**	**46,875**	**40,798**	**50,831**	**68,336**

PGE Exhibit 205
Income Tax Summary
(000s)

Income Tax Expense	UE 294 2016 Test Year	2018 Test Year
Book Revenues	1,891,229	1,909,173
Book Expenses (including Depreciation)	1,483,716	1,406,707
Interest Deduction	120,306	118,756
Book Taxable Income	287,206	383,709
Production Deduction	-	9,000
Permanent Sch. M	(24,911)	(24,268)
Temporary Sch. M	97,277	45,835
Tax Taxable Income	214,841	353,143
Current State Taxes	15,495	27,459
State Tax Credits	(992)	-
Net State Income Tax	14,503	27,459
Federal Taxable Income	200,338	325,684
Current Federal Taxes	70,118	113,989
Federal Tax Credits	(49,150)	-
ITC Amortization	-	-
Deferred Taxes	38,607	18,301
Total Income Tax	74,078	159,749
Effective Tax Rate	25.79%	41.63%
Change in Taxes		85,671

Analysis of Tax Change:

Effective Tax Rate Change	15.84%
Book Taxable Income (UE 294)	287,206
Increase in Taxes Due to Higher Effective Rate	45,494
Change in Book Taxable Income (2017 vs UE 294)	96,503
2017 Effective Tax Rate	41.63%
Increase in Taxes Due to Higher Book Taxable Income	40,177
Sum of Tax Impacts	85,671

PGE Exhibit 206
Taxes Other Than Income
2014 - 2018 Test Year

Item	FERC Account	AWO	2014 Actual	2015 Actual	2016 Actual	2017 Budget	2018 Forecast
Payroll Taxes	408.1	Note 1	13,592,277	13,719,102	13,522,625	16,333,882	16,109,015
Property Taxes - Oregon	408.1	4081001	45,345,336	47,797,482	51,759,568	55,796,028	52,680,261
Property Taxes - Washington	408.1	4081002	51,839	2,201,144	1,640,162	2,059,752	2,059,752
Property Taxes - Montana	408.1	4081003	4,507,881	5,401,265	5,752,457	6,058,752	6,003,312
Franchise Fees	408.1	4081010, 4081011	41,634,096	43,406,579	43,125,386	43,546,507	47,939,369
Foreign Insurance Excise Tax	408.1	4081012	19,184	9,984	9,485	-	-
Misc. Tax & Lic Fees - Oregon	408.1	4081013	1,368,136	1,667,103	1,995,850	1,971,706	1,971,706
Misc. Tax & Lic Fees - Montana	408.1	4081014	327,767	441,288	407,253	432,504	462,504
Total Taxes Other Than Income			106,846,515	114,643,947	118,212,785	126,199,131	127,225,919

Note 1: Payroll Tax accounts include 4081004, 4081005, 4081006, 4081007, 4081008 and 4081009

PGE Exhibit 207
Rate Base (000s)
Based on Ending 12/31/17 Balance

		12/31/2017 Balance
	Plant in Service	9,879,272
Less:	Accumulated Depreciation/Amortization	(4,735,925)
	Accumulated Deferred Taxes	(634,410)
	Accumulated Deferred ITC	-
Net Utility Plant		4,508,938
Operating Materials and Fuel Stocks		80,737
Deferred Debits		
	Colstrip Common FERC Adj	-
	Glass Insulators	4,770
	Dispatchable Standby Generation	10,856
	UE 197 Generation Maintenance Deferral	684
	CET	3,923
	IT	1,737
Deferred Credits		
	Injuries & Damages	(9,137)
	Customer Deposits	(12,281)
	Incentive Adjustment (UE 283)	(8,500)
	Major Maint. Accruals (Coyote & PW1&2)	(1,107)
	Post Retirement Liabilities	(43,329)
	Misc. Other	(70)
Working Capital		56,833
Rate Base		4,594,052

PGE Exhibit 208
Rate Base Comparison
UE 294 vs. 2018 Test Year
(000s)

	UE 294 Test Year	Working Cash Requirements	Thermal Plant Maint. Accruals	Plant Additions/ Depr/Amort	Accum. Def. Taxes (bonus depr., etc.)	Misc. Other	YE 2017 Rate base
Plant in Service	9,164,479			714,793			9,879,272
Accumulated Depr/Amort	(4,225,065)			(510,860)			(4,735,925)
Accumulated Deferred Taxes/ITC	(590,561)				(43,849)		(634,410)
Net Utility Plant	4,348,853	-	-	203,933	(43,849)	-	4,508,938
Other Rate Base	34,801		550			(7,069)	28,282
Working Cash	56,518	314	-	-		-	56,833
Rate Base	4,440,173	314	550	203,933	(43,849)	(7,069)	4,594,052

PGE Exhibit 209
Unbundled Results of Operations Summary
2016 Results at Reasonable Return
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,090,691	28,486	635,813	4,859	8,430	63,013	52,039	1,883,332
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	2,214	14,079	14,463	(4,859)	(3)	(11)	(43)	25,841
Total Operating Revenues	1,092,906	42,566	650,277	-	8,427	63,002	51,996	1,909,173
Operation & Maintenance								
Net Variable Power Cost	353,586	-	-	-	-	-	-	353,586
Total Fixed O&M	162,949	10,089	121,198	-	-	-	-	294,235
Other O&M	57,596	3,943	94,139	-	1,731	53,148	43,824	254,382
Total Operation & Maintenance	574,131	14,032	215,337	-	1,731	53,148	43,824	902,203
Depreciation & Amortization	190,489	10,025	158,735	-	3,808	9,236	4,985	377,278
Other Taxes / Franchise Fee	54,002	2,645	69,762	-	350	198	269	127,226
Income Taxes	85,256	5,011	67,460	-	788	198	1,036	159,749
Total Oper. Expenses & Taxes	903,878	31,713	511,294	-	6,678	62,780	50,114	1,566,457
Utility Operating Income	189,028	10,853	138,983	-	1,748	222	1,883	342,716
Rate of Return	7.46%	7.46%	7.46%	N/A	7.46%	7.46%	7.46%	7.46%
Return on Equity	9.75%	9.75%	9.75%	N/A	9.75%	9.75%	9.75%	9.75%
Average Rate Base								
Utility Plant in Service	5,199,280	339,986	4,154,559	-	43,464	86,928	55,055	9,879,272
Accumulated Depreciation	2,300,913	161,963	2,154,246	-	16,243	76,573	25,988	4,735,925
Accumulated Def. Income Taxes	454,001	37,479	127,862	-	4,112	9,679	1,277	634,410
Accumulated Def. Inv. Tax Credit	-	-	-	-	-	-	-	-
Net Utility Plant	2,444,366	140,544	1,872,451	-	23,109	677	27,790	4,508,938
Operating Materials & Fuel	61,604	576	18,556	-	-	-	-	80,737
Misc Deferred Debits	10,871	4,814	1,316	-	609	1,575	1,678	20,863
Misc. Deferred Credits	(15,748)	(1,610)	(47,831)	-	(522)	(1,556)	(6,051)	(73,318)
Working Cash	32,794	1,151	18,550	-	242	2,278	1,818	56,833
Total Average Rate Base	2,533,887	145,476	1,863,043	-	23,438	2,974	25,235	4,594,052

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Net Variable Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Mike Niman
Terri Peschka
Aaron Rodehorst

February 28, 2017

Table of Contents

I. Introduction

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

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis.

My name is Terri Peschka. My position at PGE is General Manager, Power Operations.

My name is Aaron Rodehorst. My position at PGE is Senior Analyst, Regulatory Affairs.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial forecast of PGE's 2018 Net Variable Power Costs (NVPC). We discuss several of the updates to parameters (e.g., ancillary service assumptions) from PGE's NVPC forecast for 2017, as well as modeling changes. We compare our initial 2018 forecast with PGE's final 2017 NVPC forecast and explain why the per-unit expected NVPC have decreased by approximately $1.49 per MWh.

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

A. Our initial 2018 NVPC forecast is $353.6 million, based on contracts and forward curves as of December 8, 2016. This initial 2018 NVPC forecast represents a reduction of approximately $29.3 million relative to our final 2017 NVPC forecast filed in the 2017 NVPC proceeding (Docket No. UE 308).

Q. Will PGE make a separate 2018 test year Annual Update Tariff (AUT) filing?

A. No. The NVPC portion of this general rate case establishes the basis for recovering these costs and will be the 2018 forecast to which we compare the 2018 actual NVPC pursuant to the provisions of Schedule 126, which implements the Power Cost Adjustment Mechanism (PCAM).

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

A. Yes. Commission Order No. 08-505 adopted a list of MFRs for PGE to follow in AUT filings and General Rate Case (GRC) filings. The MFRs define the documents that PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 301 contains the list of required documents as approved by Commission Order No. 08-505. The required MFRs are included as part of our electronic work papers, with the remainder of the MFRs to be submitted within 15 days of this filing (i.e., March 14, 2017). As with PGE's NVPC filings in the 2017 NVPC proceeding, the MFR documents are designated as either "confidential" or "non-confidential".

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

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

- April 1 – Update parameters and forced outage rates; power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; and any errata corrections to our February 28 initial filing;
- July – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads;
- October – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned hydro maintenance outages; and loads; and

- November – Two update filings: 1) update gas and electric forward curves; final updates to power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; long-term customer opt-outs; and 2) final update of gas and electric forward curves.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II: MONET Model;
- Section III: MONET Updates and Modeling Changes;
- Section IV: Comparison with 2017 NVPC Forecast; and
- Section V: Qualifications.

II. MONET Model

Q. How did PGE forecast its NVPC for 2018?

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

Q. Please briefly describe MONET.

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

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

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

Q. How does PGE define NVPC?

A. NVPC include wholesale (physical and financial) power purchases and sales ("purchased power" and "sales for resale"), fuel costs, and other costs that generally change as power output changes. PGE records its net variable power costs to Federal Energy Regulatory Commission (FERC) accounts 447, 501, 547, 555, and 565. As in the 2017 NVPC proceeding, we include certain variable chemical costs and we include forecasted federal production tax credits (PTCs).[1] We exclude some variable power costs, such as certain variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. Based on prior Commission decisions, certain fixed costs, such as excise taxes and transportation charges, are included in MONET. For the purposes

[1] Effective with PGE's 2017 AUT filing (Docket No. UE 308) and pursuant to Oregon Senate Bill 1547, Section 18b, PGE now defines PTCs as a variable power cost.

of FERC accounting, these items are included with fuel costs in a balance sheet account for inventory (FERC 151); this inventory is then expensed to NVPC as fuel is consumed. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, natural gas, fuel and associated financial instruments.

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

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop our initial forecast of 2018 NVPC.

III. MONET Updates and Modeling Changes

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

A. Yes. Because this is a GRC proceeding, we include not only the parameter revisions allowed under PGE's AUT (Tariff Schedule 125), but also model changes and updates.

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

A. We use the 2018 retail load forecast described in PGE Exhibit 1200.[2] Our forecast is approximately 18.3 million MWh of cost-of-service energy, or approximately 2,093 MWa, a small decrease of 10 MWa from the 2017 test year forecast presented in PGE's most recent AUT in Docket No. UE 308.

Q. What updates and model changes does PGE propose in this docket?

A. In this initial filing, we include many of the updates typically included in an April 1 AUT filing. Additional items requiring 2016 data, or for which updated data were not available in a timely manner for this filing, will also be updated in our April 1 filing. Among those items is the update to the thermal forced outage rates. We plan to file an update that includes forced outage rates based on 2013 through 2016 data by April 1, 2017, consistent with information that would be used in an initial AUT filing for 2018. By that date, we will have processed the 2016 data needed to complete the outage rate calculations. For this filing, we use the same forced outage rates, based on 2012 through 2015 data, from Docket No. UE 308. We will continue to update several of the items included under Schedule 125 as this docket proceeds.

[2] PGE's load forecast in this initial filing is consistent with the retail load forecast described in PGE Exhibit 1200. There is a slight difference between reported energy amounts, because MONET uses a calendar-month basis of the load forecast (measured at the busbar). In PGE Exhibit 1200, we describe the forecast on a cycle-month (billing basis (measured at the customer meter).

We include the following updates and modeling changes in our initial MONET runs:

1. The removal of the Bonneville Power Administration (BPA) 30/15 Variable Energy Resource Balancing Service (VERBS) costs beginning April 1, 2018;
2. Updated performance parameters for the Port Westward 1 plant;
3. Updates to wind integration modeling to reflect full self-integration of PGE's wind resources;
4. Update of the wind Day-Ahead Forecast Error (DAFE) cost and methodology;
5. Include an estimated NVPC benefit based on PGE’s full participation in the Western Energy Imbalance Market (EIM);
6. Replace the current Mist Gas Storage and Gap Services contract with the North Mist Expansion Project contract costs;
7. Include the estimated Portland Hydro Project refund; and
8. Update the forecast of transmission resale net revenue.

Q. What is the net effect on PGE’s initial 2018 NVPC forecast of these updates and modeling changes?

A. The net effect of these updates and modeling changes is an $18.1 million decrease in PGE’s initial 2018 NVPC forecast.

Q. Does PGE discuss any other items that could have an effect on NVPC?

A. Yes. While PGE is not proposing any changes in modeling methodology at this time, we do briefly discuss the status of PGE’s coal inventory levels at Boardman. Our initial NVPC forecast reflects changes in the coal inventory levels that we anticipate at Boardman. We also discuss the progress made in regards to Boardman Biomass and how this project may develop in the future.

Q. Does PGE propose any other updates and model changes in this filing?

A. Yes. There are certain updates and modeling changes that are included in the 2018 NVPC base model. A list of these updates can be found in Volume 10 of the MFRs. We do not include these updates in the list above because they consist of minor updates, corrections and modeling clean-ups.

Q. You previously listed a series of updates and modeling changes that are in your initial 2018 NVPC forecast. Are any of these updates and modeling changes related to each other?

A. Yes. PGE's participation in the Western EIM is the next phase of PGE's integrated approach to implementing solutions that enhance operational efficiency, integrate renewable resources, and optimize our generation portfolio. With our participation in the Western EIM, we no longer need BPA's VERBS solution as a component of our integrated approach to effective management of our resource portfolio. While our subsequent testimony will describe each update and modeling change in detail, Table 1 summarizes the benefits and costs that are related to each other. These benefits and costs include BPA VERBS savings, the costs associated with PGE's election to self-integrate its wind resources, and Western EIM benefits and costs, including costs not included in PGE's initial NVPC forecast.

Table 1 – 2018 Benefits and Costs Related to Western EIM Participation

	NVPC <u>Net</u> Benefits		**Western EIM Costs in 2018 Test Year***	
1	Sub-hourly Dispatch Savings	$4.2 million	Annual Fees (IT)	$0.7 million
2	Flexible Reserve Savings	$1.0 million	Incremental Labor	$1.6 million
3	Escalation of Gross Benefit to 2018 $	$0.4 million	Amortization Expense	$2.9 million
4	Less Settlement Charges (CAISO)	($0.4 million)	Property Taxes	$0.1 million
5	BPA VERBS Savings	$4.6 million	Return on Rate Base	$1.0 million
6	Less Increased Wind Integration Costs	($2.5 million)	-	-
	Total (2018 $)	**$7.3 million**	**Total (2018 $)**	**$6.3 million**

** The costs shown under "Western EIM Costs in 2018 Test Year" are not part of PGE's initial 2018 NVPC forecast. They are included in other parts of PGE's 2018 test year revenue requirement.*

A. BPA Variable Energy Resource Balancing Service (VERBS) Election

Q. Can you please briefly explain BPA's VERBS and committed scheduling?

A. Yes. Currently, PGE's owned wind resources (Biglow Canyon and Tucannon River Wind Farms) are part of BPA's Balancing Authority Area (BAA). Under its transmission tariff, BPA offers VERBS to customers with variable energy resources (VERs), such as wind, within BPA's BAA. VERBS provides capacity reserves for regulating, following, and imbalance:

- Regulating reserves are held for the moment-to-moment differences between generation and load.
- Following reserves are held for the larger differences that occur over longer periods of time within the hour.
- Imbalance reserves are held for differences between scheduled and actual generation for the hour.

BPA's provision of capacity reserves to VERBS customers is a function of the committed scheduling option made by a VERBS customer. For example, PGE presently pays the VERBS rate aligned with 30/15 committed scheduling. Under the 30/15 committed scheduling option, PGE makes four wind schedule changes per hour.[3] BPA has also offered 30/60 and 40/15 committed scheduling options in the past. Both of these options are more expensive than the 30/15 committed scheduling option, because BPA is responsible for more of the intra-hour variability of a customer's resource placed on the BPA BAA.

[3] PGE submits a schedule 30 minutes prior to each 15-minute schedule interval for the forecast of each plant's output. The forecast is based on BPA's persistence forecast, which is the one-minute average of generation from 31 to 30 minutes before each scheduling period. For example, PGE would submit a schedule for Biglow Canyon at 2:30 p.m. for generation that will occur from 3:00 p.m. to 3:15 p.m. The schedule is based on a forecast that is derived by taking the average of Biglow Canyon's generation from 2:29 p.m. to 2:30 p.m.

Q. What VERBS rate does PGE use in its initial 2018 NVPC forecast?

A. From January 1, 2018 through March 31, 2018, we use the BPA VERBS Base Service rate for 30/15 committed scheduling in our initial 2018 NVPC forecast.

Q. Does PGE's 2018 NVPC forecast include a VERBS rate beyond March 31, 2018?

A. No. On November 11, 2015, we made the necessary formal requests to BPA to enable the dynamic transfer of both Biglow and Tucannon out of the BPA BAA. Since this time, through a series of negotiations, BPA has agreed to a target date of April 1, 2018 to complete all work required for self-integrating PGE's wind resources.

Q. Is this a firm commitment from BPA?

A. Yes. Subject to extenuating circumstances outside of their control, PGE and BPA have a signed agreement indicating that all design and construction activities associated with moving Biglow and Tucannon from BPA's BAA to PGE's BAA will be completed no later than April 1, 2018. A copy of this agreement is included in our MFRs.

Q. What is BPA's published timeline for dynamically transferring generating resources out of its BAA?

A. BPA's current published process states it can take up to three years to complete all work required to dynamically transfer resources out of their BAA. However, BPA published this process after PGE submitted the request to leave.

Q. By what date did PGE originally request a completed transfer process?

A. PGE requested a date of October 1, 2017, which coincided with our entry in the Western EIM. However, BPA was unwilling to commit to completing all necessary work by this date.

Q. What reasons are behind BPA's inability to meet PGE's requested date?

A. The work involved and overall process to switch a resource from one BAA to another BAA takes considerable time and effort. There is a considerable amount of metering and telemetry equipment, communications equipment, and other assets that need to be replaced at both BPA-owned and PGE-owned substations. Both BPA and PGE must also complete a number of System and Readiness Control Center upgrades to ensure proper communications.

There are also three studies/reviews that BPA must complete before a pseudo-tie[4] is established. These studies/reviews, which must occur in sequential order, include:

1. BPA's Dynamic Transfer Capability Study (typically completed in the spring);
2. WECC's Remedial Action Scheme Review (typically completed in the fall); and
3. BPA's Local Integration Test (typically completed in the fall).

Additionally, BPA had, prior to PGE's formal request, received exit requests from two other power generators, with approximately 17 different wind generation projects.

Q. What effect does the removal of BPA VERBS beginning April 1, 2018 have on PGE's initial 2018 NVPC forecast?

A. The removal of 30/15 committed scheduling starting April 1, 2018 results in an approximate $4.6 million decrease to PGE's 2018 NVPC forecast.

B. Ancillary Service Assumptions

Q. Please briefly explain PGE's method for meeting PGE's ancillary service needs in MONET.

[4] A pseudo-tie is the specific method used to dynamically transfer PGE's generating resources out of BPA's BAA.

A. In UE 266, PGE improved MONET's Mid-C dispatch and ancillary service logic and operating constraint modeling, accounting for the implicit ancillary service abilities of PGE's Pelton and Round Butte hydro facilities. Additionally, PGE included functionality to re-dispatch (after the economic dispatch occurs) eligible thermal plants to cover ancillary service needs that are unmet by hydro resources for a given hour. In UE 294, PGE further refined MONET's thermal dispatch parameters by including the results of cost of cycling studies of our thermal resources to account for the sub-hourly scheduling and dispatch necessary to balance PGE's load and variable energy resources. These improvements resulted in a more accurate dispatch of PGE's Mid-C resources, and accounted for the role that PGE's thermal resources play in meeting PGE's ancillary service needs.

Q. Has PGE updated any of its ancillary service modeling in MONET for this filing?

A. Yes. For this initial filing, we have updated the parameters for Port Westward 1 to reflect a higher capacity factor and lower heat rate. The plant performance improvements and corresponding parameter updates result from upgrades to the Port Westward 1 combustion turbine, allowing it to withstand higher temperatures, resulting in increased net output.

Q. Does PGE plan to change the ancillary service parameters for the April 1 update filing?

A. Yes. We are still in the process of collecting and validating the most current plant parameters and ancillary service capabilities for PGE's thermal and hydro plants, as provided by PGE's power supply engineering services and plant operations personnel. To the extent that there are changes to PGE's plant parameters and capabilities, we will include the updates in the April 1 update filing.

Q. What effect does the update to the Port Westward 1 thermal plant capabilities have on PGE's initial 2018 NVPC forecast?

A. The update to the Port Westward 1 plant performance capabilities decreases PGE's initial 2018 NVPC forecast by approximately $1.5 million.

Q. Please briefly explain the cost of wind day-ahead forecast error (DAFE).

A. The cost of wind DAFE is the cost incurred to re-optimize PGE's portfolio in order to account for the difference between the day-ahead and the hour-ahead forecasts for wind generation. These costs materialize in the form of market transactions (purchases and sales) and the re-dispatch of available generation resources. Similar to prior NVPC filings, PGE forecasts this cost using the Resource Optimization Model (ROM).

Q. Has PGE updated the ROM since UE 294?

A. Yes. PGE has updated the ROM to reflect sub-hourly (i.e., 15-minute) dispatch capability and more explicit ramp rate constraints. These updates to ROM more accurately reflect the capabilities of PGE's generation resources and the reserves PGE must hold in order to integrate 15-minute wind schedule changes. With these changes, the wind day-ahead forecast error cost estimate for the 2018 test year is approximately $0.39 per MWh. A ROM summary sheet can be found in PGE's work papers.

Q. What effect does the update to the ROM DAFE have on PGE's initial 2018 NVPC forecast?

A. The update to the DAFE increases PGE's initial 2018 NVPC forecast by approximately $0.4 million.

Q. Will PGE still experience a cost of wind DAFE after switching from BPA VERBS to the full self-integration of owned wind resources?

A. Yes. The DAFE captures the costs associated with changes between PGE's day-ahead and the hour-ahead forecasts for wind. These costs, based on PGE's wind forecast, are the same regardless of whether PGE or BPA VERBS handles the hourly and sub-hourly balancing requirements of PGE's wind resources. BPA VERBS does not include balancing service for day-ahead forecast error.

Q. What other costs are associated with the full self-integration of PGE's wind resources?

A. The DAFE accounts for the changes between day-ahead and hour-ahead forecasts for wind. When PGE exits BPA VERBS, we will also be responsible for the hourly and sub-hourly balancing of our wind resources. This involves setting aside additional capacity/operating range (i.e., reserves) on PGE thermal generators in order to balance the various changes in wind generation that occur across multiple time scales. These reserves include: (1) imbalance reserves to cover the difference between the hour-ahead forecast and the hourly average real-time wind generation, (2) following reserves to cover the longer duration (5-60 minutes) intra-hour changes in real-time wind generation, and (3) regulation reserves to cover the short duration (1-5 minutes) intra-hour changes in real time wind generation.

Q. How are the costs of hourly and sub-hourly balancing of PGE's wind resources forecast in MONET?

A. To estimate the cost impact of this additional balancing requirement, PGE uses the ROM methodology[5] to develop the set of reserves needed to fully self-integrate our wind. These reserves are then used in place of both MONET's load regulation estimate and the prior

[5] Refer to Vol. 9, Step 0b and Vol. 7, Integration (Day-Ahead Forecast Error) of PGE's MFRs for detail on the ROM methodology.

30/15 load-net-wind following estimate to reflect the incremental reserve needs to fully self-integrate our owned wind resources. MONET then uses the existing dynamic capacity logic to re-dispatch resources to meet the reserve needs. The MFRs provide additional detail on the reserve methodology and the dynamic capacity logic.

Q. What effect does this update to full self-integration have on PGE's initial 2018 NVPC forecast?

A. The update to full self-integration increases PGE's initial 2018 NVPC forecast by approximately $2.5 million.[6]

C. Western Energy Imbalance Market

Q. Please describe the Western EIM.

A. The Western EIM is a voluntary, balancing energy market operated by the California Independent System Operator (CAISO) that optimizes generator dispatch within and between BAAs every five minutes. The Western EIM's operations began November 1, 2014. PacifiCorp, Nevada Energy, Puget Sound Energy, and Arizona Public Service are active participants in the CAISO-operated market. Idaho Power Company has announced planned market entry in 2018. Seattle City Light has announced planned market entry in 2019.

Q. When will PGE begin participating in the Western EIM?

A. PGE is preparing for a market entry date of October 1, 2017. This date is identified in the Implementation Agreement filed by CAISO on November 20, 2015 at the FERC. FERC accepted the Implementation Agreement between CAISO and PGE on January 20, 2016.

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[6] MONET forecasts an April 1 start date for full self-integration, consistent with the expected termination of BPA VERBS.

Q. The stipulation resolving NVPC issues in Docket No. UE 308 stated that PGE would "complete an EIM cost-benefit study to be used in its 2018 AUT filing." Please summarize the EIM issue(s) raised in Docket No. UE 308.

A. In Docket No. UE 308, PGE proposed excluding Western EIM benefits and costs from its power cost filing. PGE proposed this exclusion due to the uncertainty surrounding the level of benefits that could be achieved and the costs that would be incurred during the early stages of PGE's participation in the Western EIM. However, the Citizen's Utility Board and Staff for the Public Utility Commission of Oregon (OPUC) argued that net benefits should be included in PGE's power cost filing. For settlement purposes, parties agreed to include an EIM benefit of $1,011,000 and an EIM cost of $1,011,000 in test year power costs. PGE also agreed to complete an EIM cost-benefit study to be used in its 2018 AUT filing.

Q. Has PGE addressed this issue in its initial filing in this proceeding?

A. Yes. PGE engaged Energy + Environmental Economics (E3) to model a 2018 gross benefit for PGE's test year power costs. E3's study is included as PGE Exhibit 303. The study is structured as an addendum to the previously completed study for PGE (which was based on a 2020 study year).[7] The modeled gross benefit (less a forecast of transaction settlement charges) is included in PGE's test year power costs. The modeled gross benefit is $5.2 million (2015 $) in the E3 study.

PGE's budgeted Western EIM costs are included in PGE's test year revenue requirement. Since last year's power cost filing, PGE has entered into vendor agreements for the necessary software to participate in the Western EIM. PGE has also completed its

[7] See E3, PGE EIM Comparative Study: Economic Analysis Report, November 2015, Published as Appendix B of PGE Report "Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options", (http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf)

workforce planning to determine the staffing needed to participate in the Western EIM. The budgeted costs not included in PGE's NVPC forecast total $5.3 million.

Q. How will PGE's participation in the Western EIM benefit customers?

A. We expect the Western EIM to produce several benefits, including sub-hourly dispatch savings, flexible reserve savings, and reliability benefits. As we discussed previously, in order to estimate the 2018 benefits associated with sub-hourly dispatch and flexible reserves, PGE engaged E3 to conduct an updated benefits study.

E3's benefits study for 2018 continues to use the production simulation modeling in PLEXOS to estimate PGE's benefits from participation in the Western EIM. However, E3 has updated the study inputs to reflect differences in the study's topology and operating conditions in 2018 (instead of PGE's previously modeled 2020 study year). These updates included the addition of new Western EIM participants as well as changes to PGE's power supply portfolio to reflect 2018 operating conditions. See PGE Exhibit 303 for the study details.

Q. Please describe the first benefit, sub-hourly dispatch savings.

A. We expect the primary economic benefit to come from sub-hourly dispatch savings resulting from PGE's ability to export and import in near real time with other Western EIM participants to respond to intra-hour imbalances. In E3's study, PGE realizes power cost savings through imports and exports. PGE imports from the Western EIM to avoid production costs on its most expensive thermal generators when Western EIM prices are low. PGE exports to the Western EIM, earning net revenues, when Western EIM prices are higher than PGE's internal production costs. Gross sub-hourly dispatch savings in the 2018 scenario of E3's study were estimated to be approximately $4.2 million (2015 $).[8]

Q. Please describe the second benefit, flexible reserve savings.

A. Participation in the Western EIM allows for a reduction of flexible reserve requirements. As part of its flexible ramp sufficiency testing, CAISO calculates an EIM Diversity Benefit. The EIM Diversity Benefit is the difference between the sum of the individual flexible ramping requirements of each BAA in the Western EIM and the flexible ramping requirement for the entire Western EIM footprint.[9] A pro rata share of the EIM Diversity Benefit is allocated back to each participating BAA. In the E3 study, a modeled estimate of this lower flexible reserve requirement provided PGE with additional dispatch flexibility and led to greater sub-hourly dispatch savings. PGE's portion of gross savings due to modeled flexible reserve reductions in the 2018 scenario of E3's study was estimated to be approximately $1.0 million (2015 $).

Q. Please describe the third benefit, the reliability benefits from Western EIM participation.

A. In 2013, a FERC Staff Report addressed the reliability value an EIM can provide.[10] The Staff Report stated that "while an EIM would not be a replacement for capacity adequacy, a larger pool of resources under an EIM footprint could provide more ramping capability and respond to variations and imbalances more quickly."

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[8] PGE will also incur settlement costs in the Western EIM. PGE estimates settlement costs to be approximately $400 thousand per year.
[9] See Section 11.3.2 of the CAISO's Business Practice Manual for the Energy Imbalance Market.
[10] FERC Staff. *Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market*. February 26, 2013. https://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf

The 2013 FERC Staff Report also points out that an EIM could provide reliability benefits through enhanced situational awareness. While the models utilized to run the security constrained economic dispatch (SCED) are not reliability tools themselves, FERC argues that an "EIM could provide proactive solutions to potential reliability issues through automated redispatch every 5 minutes using SCED." By proactively signaling resources to respond to system imbalances, an EIM can potentially correct issues before they elevate to a level that would require involvement from the reliability coordinator (PEAK RC).

Q. Are there costs associated with PGE's Western EIM participation?

A. Yes. There are two general categories of costs related to PGE's participation in the Western EIM: start-up costs and ongoing O&M costs.

Q. Please describe PGE's start-up costs.

A. Prior to participating in the Western EIM, PGE must implement several key capital projects that collectively fall under a project plan known as Energy Market Readiness. Examples of these projects include:

1. *Bid-to-Bill Software*: PGE will implement software solution(s) that address all aspects of integrating into the Western EIM. This software includes advanced functionality for bidding, scheduling, and settlements.

2. *Generation and Transmission Outage Management Reporting*: PGE will align processes and software applications to effectively manage and communicate planned and unplanned outages to the market operator (i.e., CAISO).

3. *Full Network Model and Energy Management System Upgrades*: The development and maintenance of an accurate full network model and energy management system is a requirement to participate in the Western EIM. In this project, PGE will upgrade its software used in the System Control Center to ensure transmission and generation assets are modeled accurately and real-time data is exchanged between PGE and the CAISO in order to bid generation resources into the Western EIM.

We presently estimate our start-up costs to be approximately $14.3 million in capital. Amortization expense associated with Western EIM capital costs is forecast to be

$2.9 million in the 2018 test year. Western EIM capital costs are also part of PGE's 2018 rate base,[11] and we estimate property taxes to be approximately $0.1 million in the 2018 test year.[12]

Q. Please describe PGE's ongoing O&M costs.

A. PGE's ongoing O&M consists of eleven new positions (i.e., incremental labor full-time equivalent employees) needed to support PGE's participation in the market, annual fees related to IT systems and support, and variable fees paid to CAISO (i.e., settlement costs). PGE's estimate of settlement costs in its NVPC forecast is $0.4 million. PGE's estimate of ongoing O&M costs in the 2018 test year is $2.3 million.

PGE estimates annual fees related to IT systems and support to be $0.7 million per year. PGE estimates its incremental labor expense associated with Western EIM to be $1.6 million in the 2018 test year. PGE's new positions for participation in the Western EIM consist of:

1. *Energy Market Analyst (1 position):* Position will be responsible for market operations strategies and regulatory policy as it relates to the merchant role in the market (Labor in PGE Exhibit 700).

2. *Energy Market Analyst – Settlements (2 positions):* Position(s) will be responsible for market operations strategies and settlement analysis (e.g., billing and reconciliation of market charges) as it relates to the merchant role in the market (Labor in PGE Exhibit 700).

3. *Western EIM Policy Analyst (1 position):* Position will be responsible for participating in the formation of, and adherence to, regulatory and operational rules that impact the Balancing Authority's ongoing responsibilities in the market (Labor in PGE Exhibit 800).

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[11] The return on rate base in the 2018 test year is approximately $1.0 million.
[12] Property taxes are estimated to be $137,000 in the 2018 test year.

4. *Western EIM Settlement and System Specialist (2 positions):* Position(s) will manage the Balancing Authority's ongoing settlement and settlement system responsibilities in the market (Labor in PGE Exhibit 800).

5. *Energy Management System Engineer (1 position):* Position will be responsible for the development, configuration, and full-time maintenance of new EIM computer systems and interfaces used by the System Control Center to support Western EIM participation (Labor in PGE Exhibit 800).

6. *Network Model Engineer (1 position):* Position will develop and maintain updates to the Energy Management System Full Network Model, including accurate and timely data exchange requirements to the CAISO and neighboring entities (Labor in PGE Exhibit 800).

7. *System Control Center Outage Coordinator (1 position):* Position will be responsible for planning, coordinating, and scheduling transmission line outages with the CAISO, Peak Reliability Coordinator, BPA, and PacifiCorp (Labor in PGE Exhibit 800).

8. *IT Developer Analyst (2 positions):* Position(s) will provide ongoing support and maintenance of the IT applications used to support PGE's participation in the Western EIM (Labor in PGE Exhibit 500).

Q. In summary, what are the Western EIM benefits and costs included in PGE's initial 2018 NVPC forecast?

A. After escalating the E3 study results to 2018 dollars, PGE will include a gross benefit of $5.6 million less PGE's forecast of settlement costs. The net benefit in PGE's NVPC forecast is $5.2 million. The elimination of VERBS, net of incremental self-integration costs, adds an additional net benefit of $2.1 million.

Q. In summary, what other Western EIM costs are included in PGE's 2018 test year?

A. The other Western EIM costs in PGE's 2018 test year consist of PGE's ongoing O&M and the costs associated with capital. In total, we forecast these costs to be $6.3 million in the 2018 test year. The costs were listed by category in Table 1 of our testimony.

D. North Mist Expansion Project

Q. Please briefly describe PGE's use of long-term gas storage at the Port Westward/Beaver complex.

A. PGE uses storage from Mist at the Port Westward/Beaver complex to augment gas pipeline transportation service to PGE's Beaver and Port Westward plants (Units 1 and 2). While natural gas-fired resources are typically fueled with firm transportation that is equivalent to the plant's expected dispatch or its maximum generation capability, PGE's observation in practice with the Port Westward and Beaver sites is that a combination of firm transport and natural gas storage can provide a more flexible and lower cost solution than exclusively using firm transport to supply all the needs of the plant.

Since 2007, PGE has received firm natural gas storage service from NW Natural that allows PGE to store up to 1.26 million dekatherms (and withdraw up to 70,000 dekatherms per day) of natural gas in the Mist gas storage facility near Clatskanie, Oregon. PGE's confidential MFRs provide the details of the contractual terms for this service.

Q. Is this contract with NW Natural for firm natural gas storage service available to PGE for renewal?

A. No. This capacity at Mist is subject to recall by NW Natural. In the future, NW Natural intends to use its existing Mist storage to serve its core customers.[13]

Q. Does the addition of Port Westward Unit 2 to the Port Westward/Beaver complex require additional gas storage?

[13] *See* page 1.10 of NW Natural's 2014 Integrated Resource Plan for a description of Mist Recall. Commission Order No. 15-064 acknowledged NW Natural's 2014 Integrated Resource Plan.

A. Yes. Availability of gas from storage is integral to PGE's ability to provide flexible capacity, and in 2012 PGE entered into a Precedent Agreement with NW Natural for long-term no-notice gas storage services from the proposed NMEP.[14] The gas storage services from the proposed NMEP will (in conjunction with the Kelso-Beaver pipeline) meet the fueling requirements of the Port Westward/Beaver complex and replace the current natural gas storage services provided by NW Natural.

Q. Please describe the benefits of gas storage withdrawals on a no-notice basis.

A. To provide flexible capacity, PGE requires a highly flexible and dynamic fuel supply to meet the demands for peaking, load following, and wind integration services. Gas storage withdrawals on a no-notice basis provide a high degree of intra-day and intra-hour flexibility, which aligns with PGE's need for a flexible and dynamic fuel supply.

Q. Please briefly describe the NMEP.

A. The NMEP consists of an underground storage facility, including a storage reservoir, along with a 13 mile-long underground gas pipeline with above ground facilities including a well pad, compressor station and mainline block valve.

The project is located entirely within Columbia County, Oregon. The gas pipeline would originate at NW Natural's North Mist Gas Storage facility and end at the Port Westward Industrial Park facilities located approximately five miles north-northeast of Clatskanie, Oregon.

Q. Has NW Natural provided an estimated in-service date for the NMEP?

[14] The North Mist Expansion Project was previously referred to as the Emerald Facility or Emerald Project.

A. Yes. Based on NW Natural's current project schedule, PGE anticipates the NMEP being placed into service by October, 2018. Table 2 below lists key milestones, both completed and estimated.

Table 2
North Mist Expansion Project Milestones

Milestone	Actual/Scheduled Completion
PGE Provides NW Natural with Notice to Proceed	September 30, 2016*
Initiate Drilling of First Well	November 2016*
EPC Contractor Mobilizes Onsite and Starts Construction	March 2017
Completion of Well Drilling	August 2017
Completion of Major Construction Activities	December 2017
Inject Base Gas and Working Gas into Reservoir	January 2018 through October 2018
Commissioning Activities for Pipeline and Compressor Station	January 2018 through October 2018
Project In-Service	October 2018

** Asterisk identifies Actual Completion dates*

Q. Is there a potential for the in-service date to occur prior to October 2018?

A. Yes. NW Natural's current project schedule is designed to place the NMEP into service prior to the winter heating season. If an earlier in-service date is identified, PGE will adjust power costs accordingly in future power cost updates in this docket.

Q. Has the estimated in-service date for the NMEP changed since the Precedent Agreement was signed?

A. Yes. When PGE and NW Natural entered into the Precedent Agreement, the "target commencement date" of the NMEP was May 31, 2016, which was not a guaranteed commencement date. Project development activities such as preliminary engineering, permitting, and the acquisition of property rights have taken more time than originally anticipated.

Q. How has PGE addressed its storage needs since late 2014, when PGE placed Port Westward Unit 2 into service?

A. Pursuant to the Precedent Agreement, on January 30, 2015, PGE notified NW Natural that "gap services" would be required starting May 1, 2015.[15] The "gap services" allow for the extension of the existing Mist Storage agreement while the NMEP is constructed and commissioned. These "gap services" include an additional 360,000 dekatherms of storage capacity and an incremental quantity of maximum daily withdrawal capability equal to 20,000 dekatherms per day. PGE anticipates that this "gap service" will conclude shortly after the NMEP is placed into service. In its initial NVPC forecast, PGE models the NMEP in-service date to be October 1, 2018 and concludes "gap service" on November 30, 2018.

Q. Please briefly describe the Precedent Agreement PGE has entered into with NW Natural for no-notice underground gas storage services from the NMEP.

A. Under the Precedent Agreement, NW Natural will construct the NMEP to provide no-notice service to the Port Westward/Beaver complex. As part of the Precedent Agreement, PGE and NW Natural will enter into an Oregon Storage Service Agreement. The Oregon Storage Service Agreement sets forth the maximum injection, maximum withdrawal, and maximum storage quantities provided to PGE. The Oregon Storage Service Agreement provides PGE with a maximum of 2.54 million dekatherms of firm storage capacity, and a maximum 120,000 dekatherms of daily withdrawal quantity in the NMEP. As part of the Oregon Storage Service Agreement, NW Natural will provide no-notice withdrawal firm storage service for 30 years, with possible extensions for a cumulative service term of 80 years. PGE's confidential MFRs provide the details of the contract's terms.

[15] In May 2015, PGE began obtaining "gap services" from NW Natural.

NW Natural will finance and construct the facility and provide service to PGE under NW Natural Rate Schedule 90. Service under the agreement will be at cost-based rates.

Q. What effect does the Oregon Storage Service Agreement have on PGE's initial 2018 NVPC forecast?

A. Service under the agreement will increase PGE's 2018 power costs in its initial NVPC forecast by $2.5 million. This increase includes the power cost impact of concluding "gap service" two months after the modeled NMEP in-service date of October 1, 2018.

Q. Is the Oregon Storage Service Agreement the least-cost option for PGE's gas fueling needs at the Port Westward/Beaver complex?

A. Yes. Table 3 summarizes PGE's fueling sources prior to (and after) the addition of Port Westward Unit 2. Our alternative would be to fuel the plants with more firm gas transportation, but any viable alternative would need to replace 120,000 dekatherms per day of NMEP storage, which provides no-notice storage service.

Table 3
Beaver/Port Westward Site Fueling

Fueling Source (Dth / Day)	Prior to PW Unit 2	During Gap Services	After NMEP
Mist Storage*	70,000	90,000	120,000
Firm Gas Transport	103,305	103,305	103,305
Delivered Gas	14,195	39,195	9,195
Total Fuel Position	187,500	232,500	232,500

**Maximum withdrawal quantities; Subject to ratcheting once inventory level drops below 50 percent*

PGE is not aware of available space on the Williams NW Pipeline, and based on proposed expansion rates published by the Williams NW Pipeline, firm gas transportation would be $24.5 million per year.[16] The estimated first-year costs associated with Mist Storage are less.[17]

Additionally, due to scheduling and operational constraints on its system, the Williams NW Pipeline cannot provide the intra-day scheduling flexibility that the no-notice storage service can provide. As we noted at the beginning of our testimony, the no-notice service provides PGE with a highly flexible and dynamic fuel supply to meet the demands for peaking, load following, and wind integration services.

E. Portland Hydro Project

Q. Please describe the agreement reached in Docket No. UE 308 regarding the expiration of the Portland Hydro Project Power Purchase Agreement (PPA).

A. PGE has a PPA with the City of Portland for the output of the hydroelectric facilities on Reservoirs No. 1 and No. 2 on the Bull Run River (i.e., Portland Hydro Project). This PPA will expire on August 31, 2017, and after the contract's expiration, PGE will likely receive a refund from the City of Portland.[18] However, the final amount and timing of the distribution will be uncertain until PGE reaches agreement on the final amount with the City of Portland after the PPA expires. Due to this uncertainty of exact amount and timing, PGE agreed to include a $9.4 million decrease to our 2018 NVPC forecast to reflect the projected refund from the City of Portland. Additionally, PGE and the stipulating parties in Docket No. UE 308 agreed that if PGE receives an amount different from $9.4 million that PGE will include the difference, with interest, in our 2019 NVPC forecast.

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[16] $24.5 million = 120,000 dekatherms per day multiplied by $0.56 per dekatherm per day
[17] See PGE's confidential MFRs for an estimate of the first-year costs associated with NMEP storage.
[18] This refund will result from the final settlement of a contract provision known as the Renewal and Replacement Fund.

Q. What effect does this have on PGE's initial 2018 NVPC forecast?

A. Including this refund decreases PGE's initial 2018 NVPC forecast by $9.4 million.

F. Transmission Resale Net Revenue

Q. Please define transmission resale net revenue in this context.

A. As stated in the joint testimony supporting the stipulation reached in Docket No. UE 266 (Stipulating Parties/100/p. 13/lines 7-10):

> *PGE transmits power to its customers using BPA Point-to-Point (PTP) transmission contracts. When opportunities arise, PGE can "resell" these transmission rights on a short-term basis. While these sales generate incremental revenues, the sales are not typically costless to transact.*

Q. In the 2014 NVPC proceeding, what did the stipulating parties agree to with respect to transmission resale net revenue?

A. The stipulating parties agreed that beginning with its 2015 NVPC filing, PGE would include a proposed forecast of transmission resale net revenue and an explanation of how the forecast was created.

Q. How has PGE effectuated the forecast of transmission resale net revenue since 2015?

A. Since Docket No. UE 286, PGE has included the revenues from a long-term transmission resale agreement in MONET.

Q. Does MONET include any long-term transmission resale agreements for 2018?

A. No. PGE has not secured any agreements for 2018. PGE is exploring the possibility of other long-term transmission resale contracts, but does not have any executed agreements.

Q. How has the market for transmission resale revenue changed over the last number of years?

A. Over the last couple of years, PGE has seen a marked increase of transmission capacity available for short-term resales. As a result, PGE has seen a softening of demand and prices for this service.

Q. Has PGE included a forecast of transmission resale net revenue for 2018?

A. Yes. In lieu of securing a long-term agreement for some portion of our transmission capacity, we have included a forecasted net benefit related to transmission sales for resale. The details behind this forecast of transmission resale net revenue are provided in the MFRs.

Q. What effect does this have on PGE's initial 2018 NVPC forecast?

A. Including a forecast of transmission resale net revenue reduces PGE's initial 2018 NVPC forecast by approximately $2.8 million.

Q. Does PGE expect to update transmission resale net revenue later in this case?

A. If PGE secures a new long-term transmission resale agreement before the conclusion of this proceeding, we propose to replace our current estimate with the terms of that agreement.

G. Other Items

Q. Please provide an update to the Boardman Biomass Project.

A. To date, PGE has (1) completed a co-fire test burn, using torrefied biomass and coal as fuel in 2015 and (2) begun building in 2016 towards a 100 percent biomass test burn, which we expect to complete in the first quarter of 2017.

Q. Please provide more detail regarding PGE's most recent biomass test at Boardman.

A. In early December 2016, PGE conducted three separate biomass tests. These tests took 16 hours over three separate trials, consuming 400 tons of torrefied biomass and yielding close to 800 MWh of renewable energy. The tests were conducted using a single pulverizer on torrefied biomass and five other pulverizers using Powder River Basin (PRB) coal. The December 2016 tests showed that:

1. Torrefied biomass exhibited good flame and combustion quality; and
2. Biomass torrefied to 8,700 Btu/lb yields larger particles that do not grind as small as Powder River Basin coal (PRB coal is 8,500 Btu/lb).

Based on this difference in particle size, PGE must make small modifications to the pulverizer. Additionally, PGE must increase the airflow carrying the pulverized fuel, in order to adequately grind and deliver the torrefied biomass to the burner tip.

Q. Please summarize the testing to be performed in early 2017.

A. PGE performed a longer test using one pulverizer in early February, 2017. Based on the success of this test, a multiple pulverizer test burn will be completed with instrumentation at the flue gas stack in place to assess emissions (e.g., NOx, SOx, Particulate, Hg) associated with combusting torrefied biomass. The results of these tests will assist in determining if additional air quality control equipment would be necessary for biomass to be commercially compliant.

Q. Assuming the 2017 tests are successful, what are the next steps that PGE is planning?

A. Assuming that the completion of the 100 percent biomass test burn is successful, the next step towards establishing a technical “proof of concept” with converting Boardman from coal to biomass would be conducting one or more multiple-day 100 percent biomass test burns. With multiple-day test burns, PGE will be able to evaluate fully the power produced and effects on the plant of an extended burn. In general, this longer test should affirm that renewable, torrefied biomass will: (1) grind well, (2) burn well, and (3) demonstrate acceptable ash behavior at the back end of the plant; and do all of this on a consistent and comparable basis as Boardman's current PRB coal.

Q. Does PGE's 2018 NVPC forecast include any costs associated with the Boardman Biomass Project?

A. Not at this time. PGE is still in the initial stages of establishing the necessary steps that would need to be taken in order to secure the fuel needed. We are evaluating the cost and probability that this could be accomplished in the 2018 timeframe. We expect to know more information over the next couple of months and may propose an update to NVPC early in this proceeding.

H. Forthcoming Updates

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

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

Q. Are there other items that PGE expects to update in the April 1 filing?

A. Yes. PGE typically updates the average hydro energy inputs to MONET using the most recent Headwater Benefits Study, conducted by the Northwest Power Pool. This study uses stream flow data from August 1928 through July 2008 to produce a simulated regulation of 80 water years. We are currently validating the results of the study after applying standard base adjustments to the model to match other hydro inputs to MONET (such as removing

PGE hydro maintenance, changing to continuous mode, and adjusting for end-of-study reservoir content). We will complete this validation and update MONET from the 2013-2014 Study to the 2015-2016 Study for the April 1 filing.

Q. Are there other items that may require updates?

A. Yes. Consistent with PGE's 2013 IRP Action Plan acknowledged by the Commission in Order No. 14-415, PGE continues to engage in efforts to retain legacy hydro resources in a cost-effective manner for customers. In particular, PGE continues to discuss a new agreement with Douglas County for a share of the energy produced at Wells. For a description of the Wells project, see Appendix D of PGE's 2016 Integrated Resource Plan.[19]

Additionally, we are continuing to monitor PGE's coal inventories at Boardman. While MONET currently models no difference in the carry forward (i.e., "roll over") of shortfall tons of coal (i.e., undelivered rail traffic volume) between years,[20] additional analysis may lead us to propose a larger roll over amount of shortfall tons into 2018 than the amount of shortfall tons assumed to be carried forward into 2019.[21] See PGE's confidential MFRs for the details on Boardman's assumed beginning and ending coal inventories and roll over amounts.

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[19] See page 379 of PGE's 2016 IRP located here: https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning#

[20] This methodology is consistent with the settlement reached in Docket No. UE 308.

[21] Under PGE's rail transportation contract with the BNSF Railway Company, PGE has the option to carry forward (i.e., "rollover") shortfall tons if it cannot meet minimum shipment requirements in a given year.

IV. Comparison with 2017 NVPC Forecast

Q. Please restate PGE's initial 2018 NVPC forecast.

A. The initial forecast is $353.6 million.

Q. How does this 2018 NVPC forecast compare with the 2017 forecast used to develop NVPC in Docket No. UE 308 and approved in Commission Order No. 16-419?

A. Based on PGE's final updated MONET run for the 2017 test year, the NVPC forecast was $382.9 million, or $20.78 per MWh. The initial 2018 forecast is $353.6 million, or $19.29 per MWh, which is approximately $1.49 per MWh less than the final forecast for 2017.

Q. What are the primary factors that explain the decrease in NVPC forecast for 2018 versus the NVPC forecast for 2017 in Docket No. UE 308?

A. Table 4 shows changes in NVPC by factor between 2018 and 2017.

Table 4
Forecast Power Cost Difference 2018 vs. 2017
($ Million)

Factor	$ Effect*
Hydro Cost and Performance	(4.4)
Coal Cost and Performance	(10.3)
Gas Cost and Performance	(25.9)
Wind Cost and Performance	6.8
Contract and Market Purchases	5.8
Market Purchases for Load Change	(3.8)
Transmission	2.6
Total	**(29.3)**

** Numbers may not total due to rounding.*

A primary factor contributing to the decrease in NVPC is the reduction in power costs related to gas-fired generation. This is due to the expiration and replacement of certain short-term gas hedging instruments. Additionally, decreases in our coal and hydro cost categories are partially offset by slight net increases in our wind resource and transmission costs. These increases are primarily due to the expiration of PTC generation associated with phase 1 of PGE's Biglow Canyon Wind Farm and lower expected market prices for transmission sales for resale. As we discussed in Section III of our testimony, our load forecast for cost-of-service energy is approximately 2,093 MWa, a decrease of 10 MWa from the 2017 NVPC forecast in PGE's most recent NVPC proceeding in Docket No. UE 308.

V. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including net variable power cost forecasting. The Financial Analysis group supports the Power Operations, Corporate Planning, and Rates & Regulatory Affairs groups within PGE.

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

A. I received a Bachelor of Arts degree in Finance from Portland State University. I have been employed at PGE since 1999 in the following positions: Risk Management Analyst, Manager of Risk Management Reporting & Controls, and my current position General Manager of Power Operations. Before joining PGE, I worked at PacifiCorp from 1980-1999 in various retail, wholesale, planning, and mergers and acquisition positions. In my current position, I am responsible for managing the Power Operations group that coordinates the NVPC portfolio over the next five-years.

Q. Mr. Rodehorst, please describe your qualifications.

A. I received a Bachelor of Science degree in Business Administration from Kansas State University in 2002 and a Master of Environmental Management from Duke University in

2007. I have been employed at PGE since 2014 as a Senior Analyst in the Rates and Regulatory Affairs Department. Prior to joining PGE, I worked at Pacific Gas & Electric (PG&E) in the company's Renewable Energy Department. At PG&E my duties focused on renewable energy policy, compliance with California's Renewable Portfolio Standard and renewable procurement strategies. I have also worked for the Bonneville Power Administration where my duties focused on power price forecasting.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
301	List of MFRs per OPUC Order No. 08-505
302C	February 28 Initial Filing MONET Output Files and Assumptions Summary
303	PGE Western Energy Imbalance Market Addendum: 2018 Scenario

ORDER NO. 08-505

Minimum Filing Requirements
July 7, 2008

General

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

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

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

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

Delivery Timing

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

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

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

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

Direct Case Filing

Applicability

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

Summary Documents

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

Supporting Documents and Work Papers for the Following

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

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

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

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

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

       Electric Physical Contracts
       Electric Financial Contracts
       Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

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

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

Historical Operating Data

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

Update Filings

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

EXHIBIT 302C

Confidential

PGE Energy Imbalance Market Addendum: 2018 Scenario

November 2016

PGE Energy Imbalance Market Addendum: 2018 Scenario

November 2016

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Jack Moore, Nora Xu, Brian Conlon, and Roderick Go
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Table of Contents

Executive Summary

Portland General Electric Company (PGE) engaged E3 to conduct an updated study for year 2018 to model the projected economic benefits of PGE's participation in the CAISO EIM. As with the 2020 study, this study seeks to identify the gross savings potential of PGE's participation in the CAISO EIM, and does not investigate the initiation, labor, or operating costs associated with an EIM. The analysis methodology used is consistent with the EIM study that E3 completed for PGE in 2015 (which was based on a 2020 study year).[1]

Similar to the earlier EIM study for PGE, this current analysis uses production simulation modeling in PLEXOS to estimate PGE's benefits resulting from participation in the EIM. The analysis compares PGE's real-time generation costs as an EIM participant, as well as any revenues or costs from transactions with other EIM participants, against those of a business-as-usual (BAU) case in which PGE does not participate in the EIM.

The BAU simulation case includes operations of a "current EIM", consisting of an updated set of seven other BAAs assumed to be also participating in

[1] See E3, PGE EIM Comparative Study: Economic Analysis Report, November 2015, Published as Appendix B of PGE Report "Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options", (http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf)

the EIM in 2018. These EIM participants (other than PGE) are listed in the table below.

This 2018 analysis indicates that EIM participation is projected to create $4.2 million in dispatch savings for PGE (compared to a BAU case in which PGE does not participate) as well as $1.0 million in additional savings from pooling of flexible reserves.

Table 1: BAA Participants in EIM in 2018 BAU Case

Current EIM participants for BAU Case
Arizona Public Service (APS)
CAISO
Idaho Power Company (IPC)
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)

1 Study Assumptions and Approach

Portland General Electric Company (PGE) engaged E3 to conduct an updated study for year 2018 to model potential economic benefits of PGE's participation in the CAISO EIM. As with E3's 2015 EIM study for PGE (which focused on the 2020 study year), this study seeks to identify the savings potential of PGE's participation in the CAISO EIM.

1.1 Input Data Changes

The PGE EIM 2020 study base case database was used as the starting point dataset used for this updated 2018 analysis. That 2020 study database was updated to reflect differences in the expected topology and operating conditions in 2018 versus 2020. The updates for this 2018 analysis are described in more detail below and summarized in Table 2 and the updated real time transfer capability is shown in Figure 1.

- **Topology updates.** Transfer limits were updated on the PG&E Valley to PGE and on the PacifiCorp West to PGE lines to reflect PGE's anticipated transfer capabilities for the year 2018. [2]
- **Gas prices.** Gas prices were updated based on 2018 monthly forward hub prices from August 2016. Consistent with the methodology in the 2020 report, gas hub prices are translated to BA- and plant-specific burner tip prices using estimated zone-specific delivery charges developed for the NWPP EIM Study.[3]
- **Generation updates.** At PGE's direction, E3 updated several plants in PGE's generation fleet to reflect their status in 2018. E3 modified the status of Boardman Plant, scheduled to close in 2020, to be included in 2018 and used data from PGE to update the unit's start-up cost, maximum ramp up and down, minimum down time, heat rate, maximum capacity, and minimum stable level. Additionally, E3 included the Wells Hydro Project as part of the portfolio of Mid-C hydropower generation shares to reflect PGE's expectation (as of the initiation of this study) regarding potential expiration of contracts in August 2018 for PGE and other EIM participants.
- **Renewable generation updates.** E3 scaled renewable generation by BAA to match to data available for units in WECC TEPPC 2026 and expected to be online by 2018. E3 cross-referenced this data with renewable generation reports in EIM

[2] Compared to the original 2020 study base case, CAISO to PGE transfer capability was increased from 450MW to 600 MW; PACW to PGE transfer capability was decreased from 448MW to 276MW and PGE to PACW transfer capability was decreased from 448MW to 306MW. Original 2020 transfer capabilities can be found in E3's 2015 PGE EIM Comparative Study.
[3]The NWPP EIM study was published in October 2013 and can accessible at: http://www.nwpp.org/documents/MC-Public/NWPP_EIM_Final_Report_10_18_2013.pdf

participants' IRPs when possible. In the CAISO territory in California, the resource mix was updated to reflect currently projected renewable generation levels for 2018 based on CAISO and CEC data. As with the 2020 database, estimates of rooftop PV are included in CAISO solar. PGE provided updates for its forecasted levels of wind generation for 2018.

+ **Load updates.** Loads were updated for each BAA by scaling monthly energy to forecasted levels reported in the WECC Load and Resources (LAR) data 2016 submittals by Western BAAs, with the exceptions of PGE and CAISO. PGE load was scaled to monthly energy totals provided by PGE staff. In CAISO, load was scaled to monthly forecasts from the CEC IEPR 2015. Overall, WECC load forecasts have been reduced in the 2018 case compared to the 2020 database, both due to the nearer year to model (2018) and the more updated vintage of load forecast data which typically reflects slower WECC load growth.

Figure 1. Real-time Transfer Capabilities across the CAISO EIM with PGE Footprint

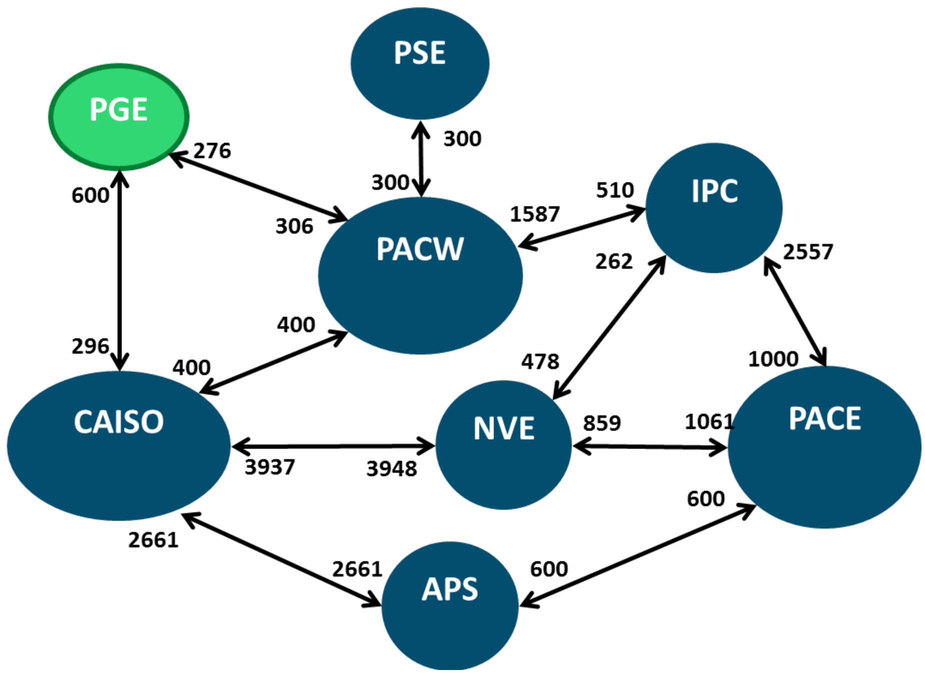


Table 2. Summary of Input Data Modification between the 2018 and 2020 EIM Study

	PGN Portfolio		EIM Members Portfolio and WECC Portfolio	
Scenario year	**2018**	**2020**	**2018**	**2020**
Load	Provided by PGE; 14.4% reduction on average from 2020 to reflect 2018 and newer data	From NWPP EIM Study by PNNL from 2013; load forecast based on TEPPC 2020 PC0 scenario	Scaled for 2018 to WECC Load and Resource data based on 2016 submittals by BA; generally lower than 2020 data	From NWPP EIM Study by PNNL from 2013; load forecast based on TEPPC 2020 PC0 scenario
Gas Price	PGE August 2016 projection of 2018 monthly forward prices for Western hubs	PGE Q2 2015 projection of 2020 monthly forward prices for Wes tern hubs	PGE August 2016 projection of 2018 monthly forward prices for Western hubs	PGE Q2 2015 projection of 2020 monthly forward prices for Western hubs
Generation	Boardman plant online	Boardman assumed retired; 400MW gas replacement	--	--
	Wind Portfolio is 717 MW	Wind portfolio is 1074 MW	EIM participants' wind and solar scaled to best information from IRPs and TEPPC 2026 Common Case generator list; CA updates from E3 & CEC solar projections	NWPP EIM study report data updated for certain BAAs based on technical review; CA updated to newer projections
	PGE Wells' contracted output included Jan. – Aug.	PGE's contracted output removed for full study year	AVA, PACW, PSE contracted output included Jan. – Aug.	AVA, PACW, PSE contracted output included for full year
	Colstrip units 3 and 4 not dispatchable in real time	Colstrip units 3 and 4 dispatchable in real time including to the EIM	EIM participants' shares of Colstrip 1-4 not dispatchable in real time	Colstrip ownership shares dispatchable in real time to owners' BAAs.
Transmission	Max transfer from PGE to PacifiCorp West (PACW) updated to 306 MW; max transfer from PACW to PGE updated to 276 MW	Max transfer from PGE to PACW limited to 448 MW; max transfer from PACW to PGE limited to 448 MW	EIM connections added to Idaho Power Company and Arizona Public Service	EIM connections reflected in diagram included in 2020 EIM study report
	Max transfer from COB to PGN updated to 600MW; max transfer from PGE to COB remains 296 MW	Max transfer from COB to PGE limited to 450 MW; max transfer from PGE to COB limited to 296 MW	--	--
EIM participants before PGE joins	--	--	Arizona Public Service (APS), California ISO, Idaho Power Company (IPC), NV Energy (NVE), PacifiCorp (PACW & PACE), Puget Sound Energy (PSE)	California ISO, NV Energy (NVE), PacifiCorp (PACW & PACE), Puget Sound Energy (PSE)

2 EIM Benefit Results

2.1 Benefits to PGE

Table 3 below summarizes the simulated annual benefits to PGE from participation in the EIM in 2018. Each column in the table represents the incremental benefit to PGE from participation in the EIM. The first column focuses on dispatch cost savings and assumes no cost savings from flexible reserve pooling, while the second column reports the incremental (additional) cost savings that PGE could realize from flexible reserve pooling. Flexible reserve pooling uses lower reserve requirements to reflect the diversity in load shapes and solar and wind resources across the expanded EIM footprint, including PGE. Monthly diversity factors are produced that reflect PGE's net load contribution to the EIM's monthly average requirements; diversity factors are applied to BA-specific reserve requirements, which are individually calculated. The impact to PGE from pooling flexibility reserves with the rest of the EIM is valued by the increase in benefits in the flexible reserves pooling case versus the dispatch cost savings only case.

Savings (in both the 1st and the 3rd columns) are calculated as the reduction in cost compared to a common BAU case in which PGE does not participate in the EIM. Overall, the cost savings are $4.2 million in the base scenario, and $5.2 million in the scenario with flex reserves savings included, which implies that flex reserves pooling provides PGE with an additional $1.0 million savings compared to the Base Scenario.

Table 3. Annual Benefits to PGE by Scenario, CAISO EIM (2015$ million)

Scenario	Dispatch cost savings to PGE	Additional Cost savings from Flex Reserve Pooling	Total savings including dispatch and reserves
Base	$4.2	$1.0	$5.2

2.2 Incremental Benefits to Current EIM Participants

Table 4 below presents the incremental benefits for the current EIM participants that result from PGE's EIM participation. In addition to savings realized by PGE, PGE's EIM participation is projected to create $1.2 million in savings to the current CAISO EIM participants in the Base Scenario. When PGE participates in the EIM and is also modeled with pooling of flexible reserves, total incremental savings for the current EIM participants (vs. the BAU case with no PGE participation) is instead $0.3 million.

Table 4. Annual Benefits to Current CAISO EIM Participants by Scenario (2015$ million)

Scenario	Incremental savings to Existing EIM Participants	Additional Cost savings from Flex Reserve Pooling	Total savings
Base	$1.2	-$0.9	$0.3

Taken together, these results imply that PGE participation provides positive incremental savings for the current EIM participants in both scenarios—with or without flexible reserve pooling. Also, total savings (for PGE plus the current EIM participants) is slightly higher when PGE is able to pool flexible reserves than in the Base Scenario. However, when PGE pools flexible reserves, PGE realizes a larger share of the total incremental savings from PGE participation (for PGE plus the current EIM participants). Flexible reserve pooling allows PGE to better position its generator commitment in the DA and HA time frame to benefit from the cost savings that the EIM enables in real time. Without pooling flexible reserves to reflect system diversity, PGE may instead hold more reserves in the HA than it needs for its own real-time use, and that extra flexibility available could result in a higher share of benefits available for other EIM participants.

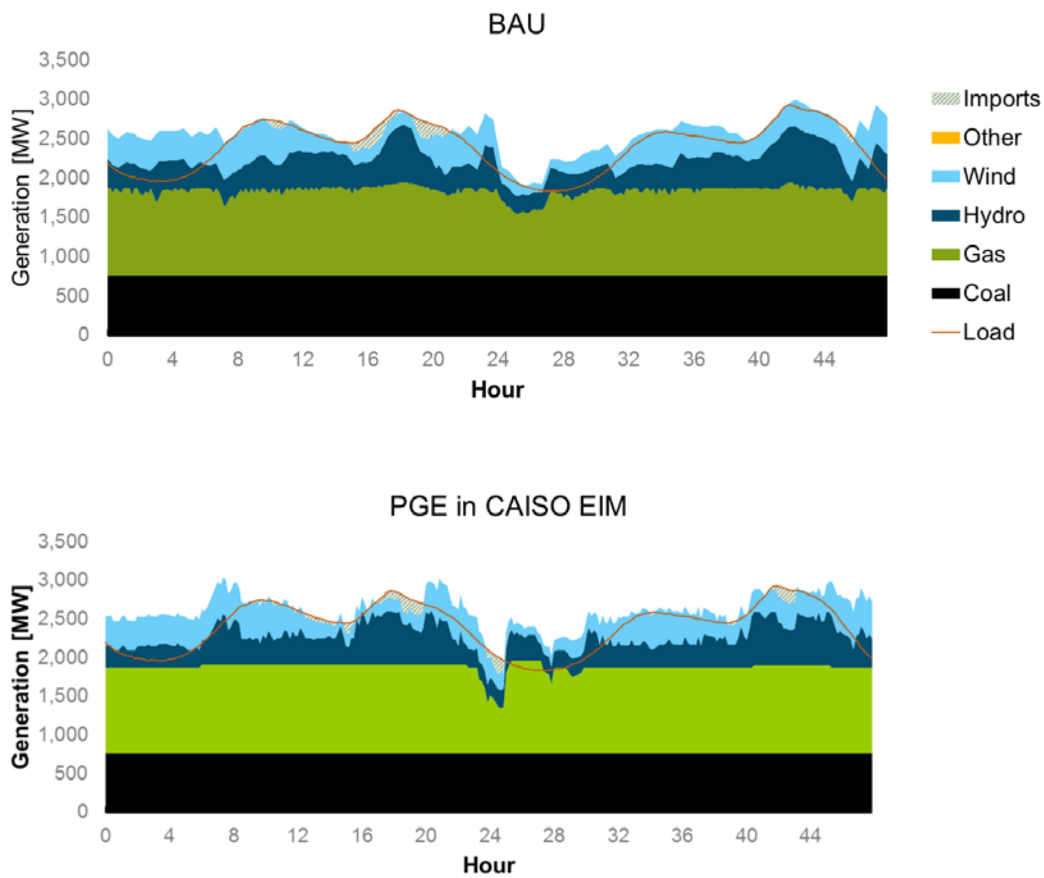
In the simulation studies, flexible reserve savings creates $1 million in additional benefits for PGE compared to dispatch cost savings in the Base Scenario (as shown in Table 4), while flexible reserve pooling results in PGE providing positive but a smaller level of savings to the current EIM participations. As a result, the simulation indicates that the incremental cost savings to current EIM participants (from PGE using flexible reserve pooling) is $0.9 million less than in the Base Scenario where PGE participates in the EIM but does not pool flexible reserves with other participants (as shown in Table 4).

2.3 CAISO EIM Results Discussion

Overall, excluding flexible reserve pooling, PGE participation in 2018 results in $4.2 million of dispatch savings to PGE, as well as $1.2 million in savings to the existing EIM participants for a total of $5.4 million in savings for the EIM as a whole. EIM participation enables PGE to export and import in real time with other EIM participants to respond to intra-hour imbalances in the 2018 case, similar to the patterns observed in the 2020 EIM analysis for PGE. PGE realizes savings both by importing from the EIM to avoid production cost on higher heat rate internal generation during intervals when EIM prices are low, as well as through exporting to the EIM, earning net revenues when EIM prices are higher than PGE's internal cost.

The following chart provides a closer graphical look at the relationship between savings and generation, displaying PGE's dispatchable generation in real time over December 12-13, 2018.

Figure 2. PGE Real-Time Dispatchable Generation, CAISO EIM, December 12-13, 2018



The upper chart shows PGE's dispatch in the BAU scenario, while the lower chart shows how that dispatch changes with PGE in the EIM. Over this two-day period, PGE both imports from and exports energy to neighboring

BAAs who are EIM participants.[4] EIM participation enables greater transaction flexibility. As a result, PGE is able reduce its generation cost by backing down certain gas units during this period.

[4] Imports are identified as the grey area which occurs in intervals where the red line (representing load) exceeds the stacked sum of PGE generation. Exports occur in intervals when the sum of PGE's generation exceeds the load line.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Anne Mersereau
Jardon Jaramillo

February 28, 2017

Table of Contents

I. Introduction

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

A. My name is Anne Mersereau. My position is Vice President, Human Resources, Diversity & Inclusion. My responsibilities include establishing total compensation policies and employee policies, continuing to strengthen the work culture at PGE, managing employee recruitment, development and retention, managing employee relations, and overseeing safety, worker's compensation and health programs.

My name is Jardon Jaramillo. While my current position is Controller and Assistant Treasurer, I was the Director of Compensation and Benefits in the Human Resources Department until January 23, 2017.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony presents and explains some of PGE's key talent management challenges. In particular, we describe how PGE's compensation philosophy is designed to address PGE's compensation challenges, and we present total compensation costs for the 2018 test year. Total compensation costs include base wages and salaries, incentive pay, and employee benefits (including pension, where applicable).

Q. What are PGE's expected total compensation costs in 2018?

A. PGE forecasts approximately $383.2 million in total compensation costs for 2018. Table 1 summarizes the 2018 costs and compares the 2018 costs to 2016 actuals.

Table 1
Estimated Total Compensation Costs ($Millions)

Component	**2016 Actuals**	**2018 Test Year**	**Delta**
Wages & Salaries	$232.6	$272.8	$40.2
Incentives	$21.6	$12.6	$(9.0)
Benefits	$83.2	$97.8	$14.6
Total Compensation*	**$337.4**	**$383.2**	**$45.9**

*Numbers may not sum due to rounding

As shown in Table 1, the net difference between 2016 actuals and forecast 2018 test year costs is $45.9 million. Looking at the component parts, the increase in forecasted wages and salaries from 2016 to 2018 is due to market-driven wage and salary adjustments and increased labor requirements needed to meet PGE's business, regulatory and customer related goals ($40.2 million). However, as described in Section III of our testimony, PGE's wages and salaries are reported in aggregate, meaning that there are both expense and capital related FTEs and costs in the reported wages and salaries. A key difference in the 2018 test year forecast, as compared to prior rate cases such as OPUC Docket No. UE 294, is that we anticipate an increased proportion of the work on PGE's capital projects will be performed by incremental employees, rather than external labor resources. This has resulted in a higher proportion of PGE's labor costs being part of capital (instead of O&M) in our 2018 test year forecast.

A primary driver of benefits costs is continued increases in health and wellness costs ($10.5 million). These increases are partially offset by a decrease in PGE's incentive request, which represents a reduction of approximately $9.0 million from 2016 actuals.

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 the Challenges that Influence It;

- Section III: Wages and Salaries;
- Section IV: Incentives;
- Section V: Benefits; and
- Section VI: Summary and Qualifications.

II. PGE's Total Compensation Philosophy and the Challenges that Influence It

Q. Please briefly describe PGE's total compensation package and its philosophy towards total compensation.

A. PGE's philosophy is to provide total compensation sufficient to attract and retain employees with strong qualifications and skills necessary to provide safe and reliable electric service at a reasonable cost. At the same time, PGE actively controls costs by targeting market median conditions for our compensation program. PGE's compensation components include:

- Wages and Salaries: PGE's non-union and union wages are designed to target the market median based on company size, geographic market and job function.
- Incentive Pay: PGE's incentive pay is designed to attract, retain, and reward employees for achieving performance goals that help PGE achieve its objectives.
- Benefits: PGE provides market-aligned health and welfare benefits. PGE also provides a pension and a 401(k) plan for retirement.[1] PGE strives to maintain a 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.

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

A. PGE is facing four strategic talent acquisition[2] challenges that affect our workforce and compensation philosophy:

1. The need to recruit well-qualified, skilled employees in a competitive marketplace;

---

[1] 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.

[2] Talent acquisition is also called "recruiting" in this testimony.

2. Developing the pipeline of talent to ensure continuity and improvement in the services we provide despite a large number of employee retirements;
3. Ensuring that our workforce reflects the diversity of our service area; and
4. Keeping our health care costs under control while providing benefits that attract and retain the well-qualified, skilled employees PGE needs.

A. Talent Acquisition

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

A. Our customers' needs and expectations are evolving in a manner that requires PGE to improve the technical skillsets and versatility of our employees. While we generally observe a need for new and different skillsets throughout PGE, 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.
- Senior managers have traditionally possessed deep subject matter expertise built through decades of experience. PGE is increasingly looking to fill these jobs with people with strong managerial abilities, rather than technical abilities, leading PGE to compete for such managerial talent with both utility and non-utility industries.
- Diversity in our customer base requires us to staff customer contact centers with a broader set of language skills. Employee candidates with the needed language skills

are difficult to attract and retain without offering premium compensation relative to PGE's market benchmarks.

Our recruiting challenges for these necessary skills continue to be most acute for several specialties.[3] We have described some similar recruiting challenges in past rate case filings, and the competition has not diminished. As the economy reaches full employment regionally and nationally, potential employees can afford to be selective about moving to a different job or a different location. For positions such as line workers, PGE is more frequently recruiting individuals who must relocate here. In this type of recruiting environment, it can be difficult to maintain market alignment[4] on compensation for positions that are difficult to fill, or to avoid having to cover relocation costs.

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

A. PGE's first focus is on developing talent internally wherever reasonably possible. One way to do this is to use cross-training opportunities to fill some senior level positions internally. This provides employees a chance to work in a position, and provides management a chance to evaluate their potential. We sometimes find it necessary to recruit senior level talent externally to find individuals with the qualifications and skills required for the position. Recent examples where PGE recruited senior level talent externally include recently filled positions in PGE's Information Technology and Human Resources, Diversity & Inclusion departments. When PGE does recruit senior level talent externally, it may involve the use of

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[3] Specialties include (1) senior managers in all areas, (2) engineering, (3) IT security, (4) senior professionals working with data, and (5) skilled trade positions such as power plant control operators, meter-service technicians, and line workers.

[4] PGE periodically evaluates the market-alignment of its total compensation program both in order to retain employees and to attract external talent. Market-alignment means maintaining total compensation that is competitive in the market.

external recruiters and can require PGE to pay premium wages and relocation costs for hard-to-fill positions.

PGE also engages in proactive hiring strategies through job fair and college campus outreach, online tools and research, and database management. PGE's employee referral program is another example of our response to the recruiting challenge. The goal of the program is to increase the number of qualified applicants for select PGE positions[5] by providing incentives to PGE employees for referring qualified external candidates. As discussed in PGE Exhibit 600, PGE is also adding employees and increasing its budget for outside services to assist with the recruitment process.

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 talent to improve in the manner PGE meets customers' needs). While the average age of PGE's employees has stabilized, approximately one-third are retirement eligible. PGE is keenly aware of gaps that exist 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, mentoring, and cross-training opportunities. We provide an extensive program of 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 is using the following workforce planning strategies:

[5] Examples of select PGE positions include journeyman lineman, SCADA engineers, and IT professionals.

- Strengthening our summer hire program that helps to develop entry-level engineering, business, and other professional candidates.
- 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. Diversity and inclusion is one of PGE's Core Principles,[6] and PGE believes that successful support of diversity and inclusion can have multiple business benefits, including higher levels of employee engagement, more effective customer engagement and improved safety performance. We believe the safety benefit results when all employees feel a greater sense of inclusion, which encourages them to take more ownership for acting in a safe manner.

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. A key challenge in PGE's efforts to attract a diverse workforce is heightened competition. All industries in PGE's service area, not just the utility industry, are striving to improve the diversity of their own workforce at the same time as PGE.

[6] PGE's Core Principles are: Safety & Health; Continuous Improvement; Ethical Business Practices; Diversity & Inclusion; Community Investment; and Environmental Stewardship.

Q. What is PGE's approach to the 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. Examples of our commitment to diversity and inclusion in 2016 include:

- Hosted a CEO forum to discuss the economic case for increased focus on diversity and inclusion in the workplace of Oregon businesses. Based on the success of this forum, PGE plans to continue this forum in 2017 and beyond.[7]
- Sponsored and participated in Oregon Tradeswomen Inc.'s annual career fair to bring awareness of trade occupations to women of all ages.
- Received a top score on the Human Rights Campaign's Corporate Equality Index.

PGE also plans to create a diverse pool of interns through partnerships with community organizations beginning in 2017. Internships are one entry point to PGE, and we are focusing on improving the diversity of our entry-points to meet our commitment to develop a workforce that is representative of the communities we serve.

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. As health care costs continue to rise faster than wages, health care costs represent a more significant share of employee total compensation. In response to this trend in health care costs, PGE has

[7] In 2015, PGE held its largest-ever Diversity Summit to discuss how diversity drives innovation and business success.

implemented creative health care benefit designs. Our changes to health care benefit designs position PGE to attract employees in a cost-effective manner for customers.

Q. What is PGE's approach to the health care cost challenge?

A. Recent changes in the health care market have increased the focus on the role of consumerism and behavioral design in health care. Consumerism and behavioral design encourage choice in health care options and more readily allow individuals to make decisions regarding quality and cost of health care in a manner similar to other goods. PGE has embraced these trends by focusing on consumerism in health care insurance plans and improving our wellness offerings. We discuss these changes in more detail in Section V of our testimony.

III. Wages & Salaries

Q. What are the major components of PGE's total wage and salary revenue requirement?

A. Total wages and salaries are comprised of the number of full-time equivalent (FTE) employees and the market-based pay structure.

Q. Please describe how PGE determines the first component, the number of FTEs required for the test year.

A. As part of the annual budgeting process, managers determine the number of labor hours in each position type that are expected to be required to accomplish their departments' work to meet PGE's goals and requirements for the coming year. PGE then converts the total labor hours into FTEs by dividing total labor hours by the number of work hours during the year. For example, an employee hired mid-year would be budgeted as one-half (or 0.5) FTE. For historical periods, FTEs reflect the actual number of hours worked divided by the number of work hours during that year.[8] See Table 2 and Table 3 for PGE's actual total FTEs (excluding overtime) for 2016 and FTEs forecast for 2018, separated by division and by employee class. Additional detail can be found in PGE Exhibit 401.

Table 2
Full-Time Equivalents by Division

PGE FTEs (straight time)	2016 Actuals	2018 Test Year*	Delta
Administrative and General (A&G)	367.3	386.0	18.7
Information Technology	272.4	316.6	44.2
Customer Service/Accounts	448.2	454.1	5.9
Generation	535.7	567.3	31.6
Transmission & Distribution (T&D)	957.7	1,127.0	169.3
Total FTEs**	**2,581.3**	**2,851.1**	**269.8**

**2018 FTEs are net of PGE's pre-filing adjustments.*

***Numbers may not sum due to rounding.*

[8] All hours over 2080 per position, per year are excluded.

Table 3
Full-Time Equivalents by Class

PGE FTEs (straight time)	**2016 Actuals**	**2018 Test Year***	**Delta**
Exempt	1,404.3	1,555.1	150.8
Hourly	427.1	486.9	59.8
Officer	11.9	12.0	0.1
Union	738.0	797.2	59.2
Total FTEs**	**2,581.3**	**2,851.1**	**269.8**

**2018 FTEs are net of PGE's pre-filing adjustments.*

***Numbers may not sum due to rounding.*

Q. Will PGE require additional employees in 2017 and 2018?

A. Yes. Overall, we will require a total of 269.8 additional FTEs in 2017 and 2018.

Q. In what areas does PGE require these additional FTEs?

A. Table 4 below provides a brief description of the work these employees will be required to perform, with a reference to a more detailed explanation in PGE's filing.

Table 4
Change in FTEs from 2016-2018

Area	**Change in FTEs**	**Explanation**	**Reference**
A&G	18.7	Security, training, staffing support	Exhibit 600
IT	44.2	Information security, infrastructure, application support	Exhibit 500
Cust Svc/Accts	5.9	Call Center support	Exhibit 900
Generation	31.6	Cyber security, regulatory requirements, operations support	Exhibit 700
T&D	169.3	System reliability, increasing customer work	Exhibit 800

Q. What are the primary drivers leading to PGE's projected FTE requirements?

A. The largest drivers are increasing regulatory requirements, new security requirements, increasing customer growth, and capital work that PGE expects to staff with employees.

Q. Are all costs related to these new employees included in PGE's revenue requirement?

A. No. Similar to prior years, PGE's FTEs and wages and salaries are provided in aggregate, meaning that there are both expense and capital related FTEs and costs. As PGE's revenue requirement only includes capital work closed to plant on or before the end of 2017, any capital labor forecast for 2018 would not be included. What is different in regard to the 2018 test year forecast is an increased proportion of the work on PGE's capital projects is expected to be performed by employees, rather than external labor resources. This has resulted in the ratio between capital and O&M for labor costs shifting from the 30/70 proportion that we normally see in our actuals and forecasted amounts to a 33.5/66.5 proportion for the 2018 test year forecast. In particular, the increase in labor costs from 2016 to 2018 exhibits a capital to O&M ratio of approximately 49.1/50.9 for the 2018 test year forecast. Applied to the 269.8 additional FTEs, the 49.1/50.9 proportion effectively assigns 132.5 FTEs to capital and 137.3 FTEs to O&M.

Q. Please provide more detail regarding the capital work being performed.

A. Beginning in 2016, largely in response to risk assessments performed by PGE's Strategic Asset Management (SAM) department, PGE began capital work to proactively repair, replace, and upgrade a number of T&D assets that were identified by SAM as posing the greatest risk to PGE's system safety and reliability. PGE Exhibit 800 provides further detail on the projects identified and the rationale behind their selection.

Q. What is PGE's strategy for hiring this many FTEs by 2018?

A. Recognizing the challenges involved with hiring additional FTEs beyond PGE's regular turnover and seasonal hiring requirements, we began the hiring of these FTEs in late 2016 with the expectation of continued hiring throughout 2017 and 2018. Table 5 below shows PGE's hiring progression, beginning with 2016 actuals. Table 5 also shows posted requisitions (i.e., employees we plan to hire soon), and a projection of the remaining employees we expect to hire in 2017 and 2018.

Table 5
Full-Time Equivalents (FTEs)

PGE FTEs (straight time)	2016 Actuals	(+) New hires through Jan. 2017	(+) Requisitions in Process through Jan. 2017	(+) Additional 2017 FTEs	(+) Additional 2018 FTEs	= 2018 Test Year*
A&G	367.3	1	1	8.8	7.9	386.0
IT	272.4	-	3	26.3	14.9	316.6
Customer Service/Accounts	448.2	1	-	4.9	-	454.1
Generation	535.7	1	3	12.4	15.2	567.3
T&D	957.7	52	115	2.3	-	1,127.0
Total FTEs	**2,581.3**	**55**	**122**	**54.7**	**38.0**	**2,851.1**

**2018 FTEs are net of PGE's pre-filing adjustments, and numbers may not sum due to rounding.*

Q. You mentioned previously that wages and salaries were comprised of two components. Please describe how PGE determines the second component, the market-based pay structure.

A. PGE periodically compares its wages and salaries to the relevant markets. To do this, we collect a wide variety of compensation studies from various organizations and experts. These data are then used to benchmark the salary ranges of various positions against similar PGE positions. PGE performs regression analyses using these data to determine the mid-point for each position classification. 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. However, as described in Section II, we sometimes find it necessary for PGE to pay premium wages for hard-to-fill positions.

Recognizing that each company can be in a different position regarding workforce age and experience, we compare salary range mid-points rather than salaries paid. This provides a more accurate comparison of salary structures. Consistent with industry standards, a PGE employee's actual salary can vary from 80% to 120% of the mid-point. The actual salary level within a range is dependent on a number of factors, including performance and experience. The consistent use of this practice ensures that our current and prospective employees are fairly compensated while costs are controlled.

Q. Have you performed any recent comparisons of your wage structure with the market?

A. Yes. In 2016, we compared our hourly non-union and salaried non-officer positions with the market. Our study showed that PGE's wage and salary structure was aligned with the market, indicating that PGE's wage and salary structure was well-designed and market-based. The details of this study are provided in our work papers.

Q. What is PGE's 2018 test year forecast for wages and salaries?

A. Table 6 summarizes total wage and salary costs for 2016 and 2018 by division.

Table 6
Total Wages & Salaries ($000)

PGE Wages & Salaries (straight time)	**2016 Actuals**	**2018 Test Year***
Administrative and General	$66,027	$76,900
Customer Accounts	$24,665	$26,638
Customer Service	$6,915	$8,103
Generation	$49,784	$55,142
Transmission & Distribution	$85,198	$106,043
Total Wages & Salaries**	**$232,588**	**$272,827**

**2018 amounts are net of PGE's pre-filing adjustments.*
***Numbers may not sum due to rounding.*

Based on industry and overall labor market data, PGE used a rate of 3.50% to escalate its non-bargaining wages and salaries for 2017 and 2018. Wage and salary increases for PGE's non-bargaining employees are budgeted to take effect after the first quarter of each year. Similarly, for union wages and salaries, PGE applied a rate of 2.54%. Wage and salary increases for PGE's bargaining employees are budgeted to take effect after February of each year.

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

A. There are two collective bargaining agreements (CBAs), one for each bargaining unit. The largest bargaining unit (i.e., the majority of PGE's union employees) covers all union employees at work sites other than Coyote, Port Westward and Carty. A second bargaining unit exists for employees at Coyote, Port Westward and Carty. The costs for both CBAs are reflected in PGE's forecast of wages and salaries for the 2018 test year.

Q. Please briefly describe how total compensation, including wages, is determined for union employees.

A. Total compensation, including wages, is the result of arm's length,[9] collective bargaining between PGE and the Union. 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). Therefore, the bargaining agreements in their entirety reflect the negotiated outcomes that both parties support.

Q. Did PGE recently renegotiate any bargaining unit contracts with the IBEW Local No. 125 (the Union)?

A. Yes. In 2016, PGE completed negotiations with the Union to establish the terms of the CBA for union employees at all sites other than Coyote, Port Westward and Carty. The terms of the CBA are in effect from February 2016 to February 2020.[10]

Q. Has PGE made any adjustments to its FTEs and wages and salaries for 2018?

A. Yes. To account for vacancies and/or unfilled positions, PGE has included an O&M reduction to its base budget wages and salaries request of $10 million. The adjustment for vacancies and/or unfilled positions translates into a 106.3 overall FTE reduction.

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[9] In an arm's length negotiation, each party to the agreement is acting independently, and in their own self-interest.
[10] The current bargaining agreement for employees located at Coyote Springs, Port Westward 1 and 2, and Carty is set to expire on August 1, 2017. We anticipate beginning negotiations in June of this year.

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.

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 corporate scorecard goals, which support our strategic direction and our commitment to core principles, such as customer satisfaction and continuous improvement.

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 is very important; it assists PGE in attracting and retaining well-qualified and skilled employees and encourages high level employee performance 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 scorecard goals with shared customer and company goals of striving to keep costs low, improve customer satisfaction, and maintain PGE's financial stability.

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

A. Incentive pay approximates 7.6% of PGE's 2018 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 3.3% of PGE's 2018 total compensation. Our pre-filing adjustment removes 100% of the Officer Long-term Incentive Program costs and 50% of the cost of all other incentives plans. Table 7 below summarizes PGE's actual incentive costs for 2016 and request for 2018. Further discussion about the four categories of incentive plans listed below is in subsections A through D below.

Table 7
Total Incentives ($000)

Incentives Plans	**2016 Actuals**	**2018 Test Year**
Performance Incentive Compensation	$8,189	$7,219
Annual Cash Incentive	$5,449	$3,470
Stock (long-term incentive plan)	$6,427	$1,564
Notables and Miscellaneous	$1,502	$331
Total Incentives*	**$21,567**	**$12,583**

** 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 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.

Q. Are PGE's incentive adjustments consistent with adjustments made by PGE in prior general rate cases?

A. Yes. Our adjustments are consistent with the adjustments made by PGE in its 2016 general rate case (i.e., Docket No. UE 294).

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 goals 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 Scorecard Goals: These scorecard 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, etc.). Strong individual performance is critical in achieving strong company performance, which in turn, leads to greater value for PGE's customers.
- Financial Performance: 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.

Q. Please describe the ACI plan's operational goals and how they align employee performance measures with customer interests.

A. PGE aligned its ACI plan with customer interests by basing the incentive payouts on PGE's success in achieving four goals described below that deliver value to customers:

- Customer Satisfaction: This goal measures the overall satisfaction of PGE's retail customer groups using results from 1) the average quarterly percent rating of the Market Strategies International (MSI) study for residential customers, 2) the average semi-annual percent rating of the MSI study for business customers, and 3) the annual results from the TQS Research, Inc. National Utility Benchmark of Service to Large Key Customers. The results of the three measures are weighted based on revenue from each retail customer group, respectively. High customer satisfaction rates are a key indicator that PGE is providing customers high quality service at a reasonable price.
- Electric Service Power Quality and Reliability: This goal uses annual results of the company's 1) System Average Interruption Duration Index (SAIDI), the average outage duration for each customer served, 2) System Average Interruption Frequency Index (SAIFI), the average number of interruptions that a customer would experience, and 3) Momentary Average Interruption Frequency Index (MAIFI), the average number of momentary interruptions that a customer would experience. Both SAIFI

and MAIFI are weighted at 15% of this goal, while SAIDI is weighted at 70% of this goal. Our customers depend on PGE to deliver and maintain a high level of system reliability.

- 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.[11]
- 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.

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. The 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."[12]

PGE's 2018 forecast for its long-term stock incentive program is $8.3 million, but our request is approximately $1.6 million for the 2018 total long-term incentive expense. Our

[11] PGE Exhibit 700 provides detail on plant availability statistics.
[12] OPUC Order No. 06-356, p.1.

request reflects the removal of the Officer Long-term Incentive Program costs and a 50% reduction for other stock incentives as we have done in past rate cases.

Q. Does PGE have other programs that reward employees' exceptional performance?

A. Yes. Notable Achievement Awards (Notables) and other miscellaneous awards are given to employees on a case-by-case basis for exceptional performance. Notables are distributed to recognize employees' outstanding work on a specific project or task. PGE's 2018 forecast for Notables is approximately $0.7 million, but our request is approximately $0.3 million, reflecting a 50% reduction.

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., Trojan decommissioning). However, these types of incentives are not included in the 2018 test year.

Q. Has PGE included any incentive costs for employees at the Boardman Plant?

A. No. As discussed in Docket No. UE 294, beginning in 2016, PGE removed all Boardman-related incentive costs from base rates. Beginning in 2016, employees working at the Boardman Plant are eligible only for the Boardman Retention/Reliability Plan, recovered separately through Schedule 145.

V. Benefits

Q. What is PGE's benefit compensation strategy?

A. 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 (wages/salaries 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 8 below, we project 2018 employee benefit costs of approximately $97.8 million. PGE's total benefit costs are expected to increase 8.4% from 2016 to 2018 on an average annual basis. The drivers of this increase, and PGE's efforts to benchmark its benefit costs, are discussed in more detail below.

Table 8
Total Benefits ($000)

Benefits Compensation Component	**2016 Actuals**	**2018 Test Year**
Health and Wellness	$41,006	$51,457
Disability and Life Insurance	$3,226	$4,216
Post-Retirement	$36,795	$39,769
Miscellaneous Benefits	$932	$1,387
Benefits Administration	$1,252	$1,004
Total Benefits*	**$83,210**	**$97,832**

**Numbers may not sum due to rounding.*

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 and 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 used by utilities and other large industries to evaluate the cost of their benefits plans.

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

A. According to the 2015 BENVAL survey, PGE's employer-paid non-bargaining medical costs along with PGE's entire benefit program are effectively at the market average. This means that PGE's medical and other benefit costs are in line with similar sized companies within the industry. These survey results from the study are provided as confidential PGE Exhibit 402C. Since the BENVAL survey is a biennial survey, PGE will participate in this survey again in 2017. Based on past experience, we anticipate receiving survey results by the end of the second quarter in 2017.

Q. Please describe PGE's peer group in the BENVAL study?

A. In general terms, PGE's peer group includes 13 regulated utilities with annual revenue ranging from $1 billion to $3 billion. The 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 U.S.

Q. Please explain why Health and Wellness costs are forecasted to increase approximately $10.5 million from 2016 to 2018.

A. The increase is primarily attributable to increases in medical and dental rates from benefit providers. In addition, increases in PGE's non-bargaining FTE account for approximately $2.6 million of the increase.

While PGE works hard to keep its medical and dental costs down, these costs are also driven by national trends and are not something that PGE can fully control. At a national and regional level, medical and dental costs continue to outpace inflation. According to a June 2016 PricewaterhouseCoopers report,[13] the projected growth rate for medical costs is forecasted to be approximately 6.5%, nationally. This compares to PGE's forecasted average annual increase of approximately 7% from 2016 actuals to the 2018 forecast.

PGE's benefits consultant, Mercer, provides PGE's forecasted rate increases for the 2018 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.

Health care plan offerings and cost sharing for the main bargaining unit are a negotiated benefit and managed by a Taft-Hartley Trust.[14] We forecast that bargaining employee medical and dental plan premium costs will increase approximately 7.0% in 2017 and 7.0% in 2018. Our forecast is based on a semi-annual survey of local insurance companies' annual claims cost trends performed by Mercer and actual employee experience in 2014 and 2015.

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

[13] See PGE's non-confidential work papers. Also available at http://www.pwc.com/us/en/health-industries/health-research-institute/behind-the-numbers.html

[14] Health care plan offerings and cost sharing for union employees at Coyote, Port Westward and Carty are the same as those offered to non-bargaining employees.

A. The largest tool PGE currently has at its disposal to help lower future health care costs for both the company and employees is to transition from traditional medical plans to Health Savings Account-qualified (i.e., HSA-qualified) medical plans. In 2016, PGE began a three-year transition to an HSA-qualified medical plan design.[15] In 2018, PGE will offer only HSA-qualified plans to non-bargaining employees. To help make the transition easier for employees, PGE has shifted some of the funds used for paying employee premiums in traditional plans over to funding a beginning balance in employees' HSAs.

Q. Please briefly describe the differences between traditional medical plans and HSA-qualified medical plans.

A. Relative to traditional medical plans, HSA-qualified medical plans are designed with higher deductibles and higher maximum out-of-pocket limits. The HSA-qualified medical plan designs encourage wise use of health care services, because employees are responsible for 100% of service costs up to the medical plan's deductible. The HSA-qualified medical plans also place a greater focus on overall wellness.

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, attendance, and productivity. 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.

[15] HSA-qualified plans are sometimes called high deductible plans.

Q. Has PGE's transition to HSA-qualified medical plans led to an increase in PGE's employer paid medical costs?

A. No. PGE has factored into its medical budget a projected shift of employees to the HSA-qualified plans due to this strategy. While this has had a net neutral effect on current medical costs, we expect the acceleration of this shift to the HSA-qualified plans to result in future medical cost savings (i.e., 2018 test year and beyond) for PGE and customers compared to the status quo.

Q. Previously you discussed the negotiation of the collective bargaining agreement for union employees at all sites other than Coyote, Port Westward and Carty. Were there any material changes to benefits in the terms of the CBA?

A. Yes. The Union agreed to include an HSA-qualified medical plan in the benefits offered to union employees. Benefit plans are an important component of the overall labor contract between the union and PGE. While union employees will also have the choice of a traditional medical plan, rising health care costs were a concern during the negotiations and it was generally agreed that offering an HSA-qualified plan would be beneficial to bargaining employees and PGE.

Q. Please explain how PGE forecast its Disability and Life Insurance benefit for 2018.

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

PGE forecasts short-term disability (STD) insurance costs of approximately $0.7 million in 2018. This represents a $0.1 million increase from 2016 and is the result of union wage increases for 2016 and 2017 coupled with incremental union FTEs.

PGE forecasts long-term disability medical costs for union and non-union employees to be approximately $2.1 million in 2018. PGE uses a forecast by Willis Towers Watson, a third party actuary, to estimate these expenses. Actual long-term disability 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 pays 85% of the health care premium for non-union employees and 90% for union employees on long-term disability.

PGE forecasts retiree group life insurance costs to be approximately $1.4 million in 2018. 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 (401k) plan and the PGE Pension Plan as post-retirement benefits. For purposes of this testimony, we also present the Health Reimbursement Account (HRA) as a post-retirement benefit.[16]

Q. What is PGE's 401(k) forecast for 2018?

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 hired after February 1, 2009. These costs change with base wage and salary levels and employee participation. From 2016 to 2018, costs associated with the 401(k) are expected to increase from $18.6 million to $22.8 million.

[16] 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.

Q. What is PGE's HRA forecast for 2018?

A. PGE's HRA provides a post-retirement benefit to cover a portion of health care expenses and premiums for employees who retire from PGE. For non-bargaining employees, only those who retire from PGE will receive any HRA benefit. For these employees, PGE places funds into a notional account for retiree HRA benefits. Additional union HRA costs relate to the accumulation of notional hours for current employees and retirees receiving current HRA benefits. Total HRA costs for 2018 are expected to be approximately $4.2 million.

Q. What is PGE's pension cost forecast for 2018?

A. PGE's 2018 pension cost is forecast to be $18.2 million (or approximately $12.7 million after capitalization). PGE's pension cost forecast includes the changes expected to be required by the proposed Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) titled, *Compensation – Retirement Benefits [Topic 715]: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. FASB will likely issue the ASU in the first quarter of 2017, and as currently proposed the ASU would take effect January 1, 2018. PGE continues to work with its external auditor to prepare for the implementation of the FASB ASU.

The amendments in the ASU will allow only the service cost component of pension costs to be eligible for capitalization. The impact of the ASU is an approximate $0.8 million increase to expense (i.e., pension expense would have been approximately $11.9 million after capitalization prior to the FASB update).

Q. Will the Federal Energy Regulatory Commission (FERC) also adopt the same accounting treatment?

A. At this time, it is unclear if FERC will adopt the provisions of the FASB ASU. As demonstrated in FERC's comments filed on April 22, 2016, FERC staff recommended that FASB not adopt the ASU as it related to rate-regulated entities under FERC's jurisdiction. PGE Exhibit 403 provides a copy of FERC's comments.

Q. Would the potential difference between FERC and GAAP reporting increase the complexity of reporting pension costs?

A. Yes. In the event FERC does not adopt the new standard and denies any requests for an accounting change, PGE expects that dual record-keeping between FERC and GAAP reporting as it relates to pension expense would be complex and costly. We anticipate that software vendors would ultimately need to design a system solution to aid regulated utilities in this record keeping if it was required.

Q. Does PGE have an alternative request regarding pension cost recovery?

A. Yes. PGE proposes that the Commission approve the following accounting treatment language:

> "PGE will record as a regulatory asset the non-service cost components of pension costs related to capital projects that otherwise would be charged to expense in periods beginning January 1, 2018 upon adoption of proposed Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) titled, *Compensation – Retirement Benefits [Topic 715]: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The regulatory asset will be included in rate base and amortized on a schedule comparable with PGE's average depreciation rates for utility plant."

This will allow PGE to: 1) continue to capitalize on the balance sheet a portion of its pension costs on a basis consistent with policies in place prior to the new FASB ASU, and 2) apply regulatory accounting treatment to ensure that GAAP financial statements reflect PGE's rate-making treatment. This treatment as a regulatory asset would most likely require PGE to file for, and receive, FERC approval for this change in accounting treatment.

Q. How is pension expense calculated?

A. Pension expense, more formally known as "FAS 87 net periodic benefit cost,"[17] 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. Based on the pension plan's asset allocation, the pension investment portfolio is expected to yield a long-term rate of return of 7.0%. This estimate is developed based on a distribution of long-term expected return information provided by Mercer Investment Management Company.

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

A. PGE uses a discount rate of 4.18%, 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 (GAAP).

Q. Will the discount rate change if the current interest rate environment changes?

A. Yes. Figure 1 shows the change in discount rates since December 2015. While discount rates have declined year-over-year, discount rates have increased significantly since mid-2016, consistent with an increase in the underlying interest rates that impact the discount rate. While interest rates are presently expected to climb over the course of 2017,

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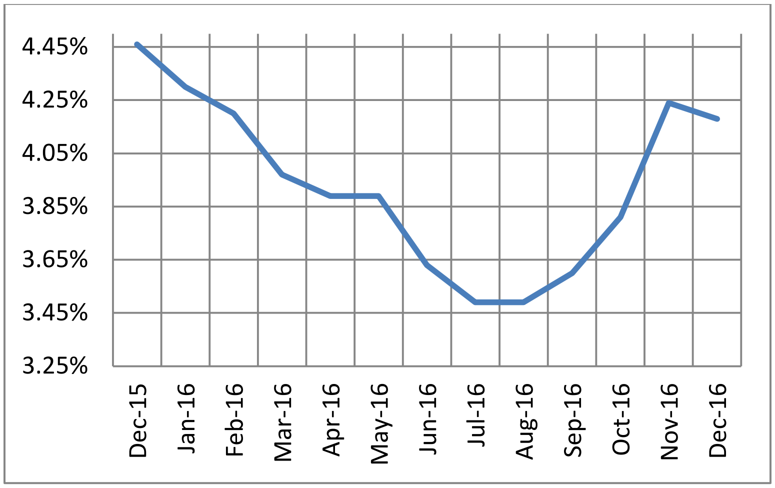
[17] PGE records its pension expense based on Accounting Standards Codification (ASC) 715, "Compensation – Retirement Benefits," which prior to July 1, 2009, was known as Statement of Financial Accounting Standards No. 87 or "FAS 87."

this expectation is subject to a large amount of uncertainty as the economic and political environment (i.e., key determinants of interest rates) continues to develop in 2017.

Figure 1: Discount Rates (December 2015 – December 2016)



Q. Does PGE have a proposal for managing the uncertainty in the discount rate assumption during this rate case?

A. Yes. PGE will continue to monitor discount rates during the course of this proceeding, and we propose submitting a final discount rate assumption for the 2018 test year pension cost no later than September, 2017. This proposal allows PGE, and parties, to monitor the interest rate environment throughout the rate case and establish a discount rate assumption that benefits from a greater understanding of more current market conditions.

Q. Is PGE's request regarding pension cost recovery consistent with Commission Order No. 15-226?

A. Yes. Commission Order No. 15-226 affirmed the Commission's policy of allowing utilities to recover pension costs through FAS 87 expense.

Q. Why are post-retirement benefits important?

A. Post-retirement benefits support employee recruitment and are an important retention device. Retirement-eligible employees are generally highly productive, very knowledgeable about PGE's work and our industry, and will work until full or close to full pension coverage. As a large percentage of PGE's workforce is eligible for retirement, these benefits are an important tool in encouraging retention and knowledge transfers between retiring and new employees.

Q. Please explain PGE's forecast cost for miscellaneous employee benefits.

A. Miscellaneous benefits are additional, low-cost tools that PGE uses to attract and retain well-qualified, skilled employees. We expect to spend approximately $1.4 million in 2018. Although small in dollars, 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.

- Education Assistance: $0.5 million – This program reimburses employees for education that enhances learning and development. It can be applied to classes that lead to a certification or undergraduate/graduate degree as well as classes that enhance technical knowledge. This program increases PGE's number of qualified employees available to fill open positions. Sponsoring career development is also a prime recruiting tool and source of employee motivation and satisfaction, which also aids retention. This program is also useful to PGE's efforts to strengthen the technical skillset and versatility of its employees.

- Service Awards: $0.2 million – As a retention and morale strategy, PGE honors employees for their years of service at five-year anniversary intervals, consistent with industry practice.
- Public Mass Transit Benefit: $0.6 million – The City of Portland continues to encourage alternatives to personal vehicle transit, and as a recruitment and retention strategy, PGE will begin to offer a public mass transit benefit. This benefit is designed to ease transit barriers for individuals, particularly those who see the cost (or limited availability) of parking as an obstacle to working in downtown Portland. Incenting travel via public mass transit into Portland also improves our ability to build a diverse workforce, because it makes downtown Portland a more accessible destination.

Q. What is PGE's 2018 cost for benefits administration?

A. PGE forecasts 2018 benefits administration costs to be approximately $1.0 million.

VI. Summary and Qualifications

Q. Please summarize your testimony.

A. PGE must provide a total compensation package sufficient to attract and retain the well-qualified 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 (SPHR) designation. My professional Human Resources career spans nearly thirty years and includes various roles at PGE for the last seven years, as well as positions with Hilton Hotels Corporation, Marsh USA Inc., and Waldron Consulting.

Q. Mr. Jaramillo, please summarize your qualifications.

A. I received a Bachelor of Arts degree in economics from Northwest Nazarene University and a Masters 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 23, 2017. My current position is Controller and Assistant Treasurer.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
401	2016-2018 FTE additions
402C	2015 BENVAL Ranking – Entire Benefit Program
403	FERC Comments on Proposed Accounting Standards Update

DIVISION	DEPT	CLASS	REG/ TEMP	Officer	2014 FTE (PGE Share)	2015 FTE (PGE Share)	2016 FTE (PGE Share)	2017 Budget FTE (PGE Share)	2018 GRC FTE (PGE Share)	FTE Delta 2016 -2018	Annual % Delta 2016-2018
A&G - INFORMATION TECHNOLOGY Total					234.81	234.78	272.41	309.30	324.21	51.8	9.1%
ADMINISTRATIVE AND GENERAL Total					348.09	370.49	367.29	405.19	412.13	44.8	5.9%
CUSTOMER ACCOUNTS Total					390.23	379.56	382.66	434.09	430.88	48.2	6.1%
CUSTOMER SERVICE Total					87.71	87.78	85.67	91.38	95.18	9.5	5.4%
GENERATING - BEAVER Total					46.89	50.17	48.91	52.51	52.51	3.6	3.6%
GENERATING - BIGLOW Total					7.16	7.44	8.07	9.00	9.00	0.9	5.6%
GENERATING - BOARDMAN Total					93.33	98.93	88.34	90.60	90.60	2.3	1.3%
GENERATING - CARTY Total					-	8.62	21.01	22.67	22.67	1.7	3.9%
GENERATING - COYOTE Total					16.22	17.06	16.98	17.88	17.88	0.9	2.6%
GENERATING - OTHER Total					294.40	302.26	309.75	335.25	345.21	35.5	5.6%
GENERATING - PORT WESTWARD Total					24.16	25.27	25.82	27.41	29.41	3.6	6.7%
GENERATING - TROJAN Total					11.80	12.11	11.85	12.15	14.85	3.0	11.9%
GENERATING - TUCANNON Total					2.06	4.43	4.99	5.00	5.00	0.0	0.1%
TRANSMISSION & DISTRIBUTION Total					926.51	922.53	957.69	1,124.97	1,165.82	208.1	10.3%
Grand Total					2,483.38	2,521.43	2,601.43	2,937.39	3,015.35	413.9	7.7%

Adjusted Totals by Division

	2014	2015	2016	2017	2018	FTE Delta	Annual %
IT	234.8	234.8	272.4	309.3	324.2	51.8	9.1%
Unfilled Position Adjustment				(7.6)	(7.6)	(7.6)	
Adjusted IT Totals	234.8	234.8	272.4	301.7	316.6	44.2	7.8%
A&G	348.1	370.5	367.3	405.2	412.1	44.8	5.9%
Unfilled Position Adjustment				(27.1)	(26.1)	(26.1)	
Adjusted A&G Totals	348.1	370.5	367.3	378.1	386.0	18.7	2.5%
Adjusted A&G/IT Totals	582.9	605.3	639.7	679.8	702.7	63.0	4.8%
Customer Accounts	390.2	379.6	382.7	434.1	430.9	48.2	6.1%
Unfilled Position Adjustment				(19.9)	(19.5)	(19.5)	
CET Program Development FTEs Subject to Deferral				(15.4)	(29.1)	(29.1)	
Adjusted Customer Accounts Totals	390.2	379.6	382.7	398.8	382.3	(0.4)	-0.1%
Customer Service	87.7	87.8	85.7	91.4	95.2	9.5	5.4%
CET Program Development FTEs Subject to Deferral				-	(3.3)	(3.3)	#DIV/0!
Incremental FTEs offset by Other Revenue	(18.9)	(19.7)	(20.1)	(20.0)	(20.0)	0.1	-0.3%
Adjusted Customer Service Totals	68.8	68.0	65.6	71.4	71.9	6.3	4.7%
Adjusted Customer Accounting/Service Total	459.0	447.6	448.2	470.2	454.1	5.9	0.7%
Generation	496.0	526.3	535.7	572.5	587.1	51.4	4.7%
Unfilled Position Adjustment				(20.4)	(19.8)	(19.8)	
Adjusted Generation Total	496.0	526.3	535.7	552.1	567.3	31.6	2.9%
T&D	926.5	922.5	957.7	1,125.0	1,165.8	208.1	10.3%
Unfilled Position Adjustment				(34.1)	(33.3)	(33.3)	
CET Program Development FTEs Subject to Deferral				(3.1)	(5.6)	(5.6)	
Adjusted T&D Totals	926.5	922.5	957.7	1,087.7	1,127.0	169.3	8.5%
Unadjusted Total	2,483.4	2,521.4	2,601.4	2,937.4	3,015.4	413.9	7.7%
Unfilled Position Adjustment	-	-	-	(109.1)	(106.3)	(106.3)	
Incremental FTEs not in prices	(18.9)	(19.7)	(20.1)	(20.0)	(20.0)	0.1	
CET Program Development FTEs Subject to Deferral	-	-	-	(18.5)	(37.9)	(37.9)	
Adjusted Grand Total	2,464.4	2,501.7	2,581.3	2,789.8	2,851.1	269.8	5.1%
Match	-	-	-	-	-	-	

EXHIBIT 402C

Confidential

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

April 22, 2016

Technical Director
Financial Accounting Standards Board
401 Merritt 7, P.O. Box 5116
Norwalk, CT 06856-5116

Re: File Reference No. 2016-200

The Federal Energy Regulatory Commission (Commission) staff respectfully submits comments on the proposed Accounting Standards Update, Compensation – Retirement Benefits (Topic 715)*: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* issued by the Financial Accounting Standards Board (FASB) on January 26, 2016. The Commission is an independent energy regulator in the United States, charged with regulating the transmission of electricity, natural gas, and oil in interstate commerce, wholesale sales of electricity and natural gas in interstate commerce, and the reliability of the electric transmission system, among other responsibilities.[1] The Commission has a fundamental responsibility to ensure that rates, terms, and conditions of providing utility service are just and reasonable and not unduly discriminatory or preferential. Moreover, the Commission requires many of its regulated entities to maintain their accounts in accordance with the Commission's prescribed accounting rules for regulatory reporting.

The basic methodology the Commission uses to establish just and reasonable rates is cost-of-service ratemaking. Under cost-of-service ratemaking, rates are designed based on a utility's cost of providing service, including an opportunity for the utility to earn a reasonable return on its investment. Entities that are subject to cost-of-service ratemaking under the Commission's jurisdiction follow accounting guidance pursuant to FASB Accounting Standards Codification (ASC) Topic 980, Regulated Operations, for GAAP accounting purposes, based on the criteria specified in ASC Subtopic 980-10.

[1] For additional information, see http://www.ferc.gov/about/about.asp.

Commission staff appreciates the FASB's efforts in proposing a revised standard to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost (together as net benefit cost) in the financial statements. The proposed Accounting Standards Update seeks to revise ASC Subtopic 980-715, Regulated Operations – Compensation – Retirement Benefits, to require separation of the service cost component from the other components of net benefit cost on the income statement. The FASB believes that this approach will improve the presentation on the financial statements because it will separate operating expense (service cost) from nonoperating expense (all other components) of net benefit cost. Following this reasoning, the proposal also allows only the service cost component to be capitalized in connection with the construction or production of an asset.

Under the Commission's accounting regulations, all components of net benefit cost are considered operating in nature and recorded in the same account within the Commission's prescribed system of accounts.[2] Similarly, when net benefit cost is allowed in cost-of-service ratemaking for a particular entity, all of the components which make up net benefit cost are typically used. All components of net benefit cost can be capitalized if they meet the capitalization criteria under the Commission's accounting regulations and will be recovered in rates over the life of the related asset. Allowing only the service cost component eligible for capitalization will increase differences between the calculated amounts for Allowance for Funds Used During Construction according to the Commission's regulatory requirements and FASB's GAAP requirements. There will also be increased differences in associated deferred income tax balances. Therefore, we recommend that the FASB not adopt this proposal as it relates to rate-regulated entities under the Commission's jurisdiction. If this proposal is adopted, it may result in misrepresentation of the economic reality of rate-regulated entities and prove to be less useful to users of the financial statements.

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[2] *See,* 18 C.F.R. Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act (2015); 18 C.F.R. Part 201, Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act (2015); and 18 C.F.R. Part 352, Uniform System of Accounts Prescribed for Oil Pipeline Companies Subject to the Provisions of the Interstate Commerce Act (2015). *See also*, e.g., *Southwestern Public Service Company,* 65 FERC ¶ 62,242 (1993); *Post-Employment Benefits Other Than Pensions, Statement of Policy*, 61 FERC ¶ 61,330 (1992).

Accounting for net periodic pension cost and net periodic postretirement benefit cost is an important matter to the Commission and the rate-regulated entities under the Commission's jurisdiction. We thank you for considering our comments to this proposed Accounting Standards Update.

Sincerely,

Bryan K. Craig

Bryan K. Craig
Director and Chief Accountant
Division of Audits and Accounting
Office of Enforcement
Bryan.Craig@ferc.gov

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Information Technology

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Cam Henderson
Behzad Hosseini
Travis Anderson

February 28, 2017

Table of Contents

I. Introduction

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

A. My name is Cam Henderson. I am the Vice President of Information Technology (IT) and Chief Information Officer (CIO) at PGE.

My name is Behzad Hosseini. I am a Director of the Office of CIO for PGE.

My name is Travis Anderson. I am the Information Security Director and Manager of IT Risk Management at PGE.

Our qualifications appear in Section V of this testimony.

Q. What is the purpose of your testimony?

A. We explain PGE's request for $94.4 million in IT costs in 2018 and compare it to 2016 actuals of $73.3 million.

Q. How is your testimony organized?

A. After this section, we have four sections:

- Section II: 2020 Vision Program Update
- Section III: IT O&M Costs
- Section IV: Information Security Operation Center (ISOC)
- Section V: Summary and Qualifications

Q. What activities or functions does PGE consider as IT?

A. IT consists of the departments responsible for developing, operating, and maintaining our computer, cyber, information, and communication systems. These systems are becoming increasingly important to all aspects of PGE's operations (with increasing scope, reliance, and use). In addition, the threats to these systems are becoming more numerous and varied. As a result, the necessity and demand for IT resources continues to increase.

Q. By how much do you forecast IT Operations and Maintenance (O&M) costs[1] to increase?

A. From 2016 to 2018, we forecast IT O&M costs to increase from $57.1 million to $71.6 million as shown in Table 1 below. Because these costs relate to all areas of PGE's operations, they are allocated or charged to appropriate operating areas and appear as part of each area's O&M costs. Since the majority of those costs relate to corporate systems, whose costs are allocated rather than charged directly to the operating areas, we discuss IT as a whole in this testimony.

Table 1
Total IT Costs ($ millions)

Category	2016 Actuals	2018 Forecast	Variance 2018–2016
Direct Charges to Operating Areas	$10.3	$17.3	$7.0
Allocated Charges to Operating Areas	46.8	56.9	10.1
Labor Adjustment	0.0	(0.9)	(0.9)
Other Adjustment	0.0	(1.7)	(1.7)
Subtotal IT Incurred	**57.1**	**71.6**	**14.5**
Labor Loadings Charged to Operating Areas	14.5	21.1	$6.5
Subtotal IT Loaded	**71.6**	**92.7**	**21.1**
2014 IT Deferral Mechanism	1.7	1.7	0.0
Total IT*	**$73.3**	**$94.4**	**$21.1**
FTEs	**272.4**	**316.6**	**44.2**

* May not sum due to rounding

Q. What are the major drivers of this increase?

A. The major drivers are increased support needed for increasingly complex and integrated systems throughout PGE and increased need in the areas of cyber and physical security.

Q. Please explain how IT costs are directly charged or allocated to the specific operating areas.

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

A. As seen in Table 1, PGE's IT costs consist of three categories: directly charged (or assigned), allocated, and labor loadings. Directly charged costs relate to systems that are specific to a given operating area, such as production, transmission, or distribution. 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 are not directly related to one specific operating area; instead, these costs apply broadly to all PGE activities and departments. These costs are first charged to a balance sheet account and then allocated to the expense accounts for the various operating areas. PGE Exhibit 501 provides the summary by operating area. Labor charged to the balance sheet has associated labor loadings and a corporate governance allocation applied per PGE's loading and allocation policies, which are submitted annually to the Public Utility Commission of Oregon (OPUC) Staff as an attachment to our Affiliated Interest Report.

Q. What do the labor loadings and corporate governance allocations represent?

A. The labor loadings represent payroll-related costs that are first charged to administrative and general (A&G – e.g., benefits and employee support) and payroll taxes, and then applied to O&M accounts, based on specific rates per allocated IT labor. Ultimately, the costs represented by these loadings begin in O&M and end in O&M so they are not specifically IT costs; rather they are payroll-related costs that follow allocated IT costs.

Q. Why do loadings increase by $6.5 million?

A. The loadings increase because the labor, on which they are based, is increasing. Labor is increasing due to escalation and more full time equivalent (FTE)[2] employees. PGE Exhibit 400 provides details regarding the underlying payroll-related costs.

Q. What does the 2014 IT Deferral Mechanism represent?

A. As part of the UE 262 settlement process, parties stipulated that 2014 O&M costs associated with developing IT systems should be capitalized and subject to a five-year amortization. The stipulation, subsequently adopted by Commission Order No. 13-459, removed approximately $8.7 million of IT development O&M expense from PGE's 2014 revenue requirement and replaced it with a regulatory asset of approximately $7.8 million, which was included in 2014 rate base. The remaining amortization expense of approximately $1.7 million represents one-fifth of the initial capitalized total.

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[2] FTEs are discussed in Section III.

II. IT 2020 Vision Update

Q. Please provide a brief summary of the 2020 Vision program.

A. In UE 215 (PGE Exhibit 600, Section IV, Part B), we described 2020 Vision as a 10-year strategy to "implement a set of projects that collectively modernize and consolidate our technology infrastructure. The ultimate purpose of this program is to replace a multitude of existing software applications with fewer 'enterprise' applications that provide integrated functionality for PGE's operations." In UE 262, we reiterated that the program's goal continues to be to implement common systems and standardized business processes throughout the enterprise to achieve efficiency and cost effectiveness. We also restated that another one of the program's primary objectives is to replace obsolete technologies with new technologies and increased functionality. In Docket No. UE 294, we stated that the last two remaining projects were to replace the current Customer Information and Meter Data Management Systems (expected to close the second quarter of 2018). These projects are part of our Customer Engagement Transformation (CET) program and are discussed in PGE Exhibit 900.

Q. What 2020 Vision projects has PGE successfully implemented to date?

A. From 2010 through 2016, PGE completed the following 2020 Vision projects:

- Work Management System (WMS) Upgrade
- Finance and Supply Chain Replacement Project (FSRP)
- Infrastructure (hardware) and Program Office
- Maximo, Mobile and Scheduling Wave 1 (MMS)
- Maximo for IT
- MyTime time collection system

- Maximo, Mobile and Scheduling Wave 2
- Geographic Information System (GIS) and Graphic Work Design (GWD)
- Outage Management System (OMS)
- Business Intelligence (BI) Systems

Q. You mention that 2020 Vision is intended to replace numerous applications with fewer enterprise systems. How many applications have you retired since 2009?

A. As shown in Table 2 below, by 2018 we will have reduced our number of applications by 40% since 2009.

Table 2
Number of PGE Applications

YEAR	TOTAL	% Reduction since 2009
2009	404	
2017	277	(31.4)%
2018	241	(40.3)%

Q. If you have fewer applications to operate and maintain, do they require less support?

A. No. While PGE has significantly reduced the number of applications being supported, on-going support is necessary due to the increased functionality, complexity, and number of interfaces of the new enterprise applications. The increased complexity and need for additional support reflects the new systems having the following:

- Increased functionality/capabilities – For example, the GWD system will provide new functions/capabilities that require incremental FTEs to maintain and support the application on an ongoing basis.
- More interfaces/integration to other systems – For example, Maximo and the Asset and Resource Manager (ARM) scheduler applications have 88 interfaces to/from

PeopleSoft Finance, Customer Information System, Field Manager and many other systems; this is compared to approximately 20 interfaces for the legacy Maximo system. The interfaces automate or eliminate the need for clients to manually key information into multiple systems and provides for consistent/common data management. While new interfaces improve efficiency and add functionality, they add complexity because interfaces have the potential for errors, or failed transactions, which becomes another area requiring IT support.

- New security policies and regulatory standards/requirements – The more complex systems, especially those with greater scope and capability, introduce further need to protect sensitive or confidential data. PGE must meet more complex standards as specified by Federal Energy Regulatory Commission, North American Electric Reliability Corporation, and other regulatory bodies. It is critical to meet additional security requirements on an ongoing basis.

III. IT Operations and Maintenance Costs

Q. What are the primary drivers of the increase from 2016 to 2018 related to direct and allocated IT charges shown in Table 1 above?

A. The increase is primarily attributable to an increase in labor costs due to the addition of FTEs required to support our growing IT infrastructure. PGE Exhibit 502 provides detailed descriptions of the positions and why they are needed. A breakdown by IT functional area is presented in Table 3 below.

Table 3
Summary of FTE Increase

Area	FTE	Description of Need
Office of CIO	7	To provide support to T&D, infrastructure fitness, software license compliance, expanded/improved IT service delivery, and Western EIM starting in 2017.
Infrastructure	9	To support eastside generation facilities, provide 24/7 IT support in the Data Center, T&D, Customer Service and the Call Center.
Risk	2	Ongoing and expanding support.
Applications	4	Ongoing maintenance and care of new software products.
Information Security Program	22	PGE is further enhancing its cyber security program based on a risk-based prioritization of enterprise-wide cyber initiatives as recommended by outside consultants. This effort is discussed in Section IV below.

Q. What considerations does PGE evaluate when deciding whether to use contractors or regular FTEs?

A. Both types of workers have value in our labor strategy. PGE uses contractors in combination with regular FTEs in order to address a number of labor needs, including, but not limited to, short-term assignments, specialized knowledge that is not generally available in our market or at our wage levels, and staffing up for projects that have a finite period and a need for an influx of skilled personnel. Regular FTEs are required to conduct work that is ongoing and integral to our operations, as those operations exist now and into the future. Regular FTEs need to understand and be able to use and maintain the IT systems that support and protect PGE's operations. We develop our employees with the expectation that they will continue to be part of our IT team, and the time invested creates more value for PGE and for customers. Further, it can take as many as 160 hours for a contractor to become proficient, which takes time away from other important tasks for the trainers and the contractor. Finally, given the rates that some contractors demand, where new positions replace existing contractors, labor costs decline.

1. Office of the Chief Information Officer (OCIO)

Q. Please describe the seven positions needed for the OCIO.

A. PGE is requesting seven FTEs[3] for the OCIO in order to meet the growing demands of our IT operations. PGE has relied on contractors to do this work in the past but with new systems coming into service that are expected to be integral to our operations, a more stable and reliably available solution is required. Contract employees are generally used on a temporary basis resulting in the need to train new contractors once an existing contractor is no longer engaged in PGE work.

Q. Why are these positions needed?

A. PGE will need two Western Energy Imbalance Market (Western EIM) positions as we approach our entrance into the Western EIM. Participation in the Western EIM introduces several new applications and interfaces to existing applications that all must be supported to meet the requirements. In addition, Western EIM will operate 24 hours, 7 days a week (i.e., 24/7). The Western EIM is discussed in more detail in PGE Exhibit 300.

[3] Described in detail in PGE Exhibit 502

To deliver IT service across the organization, we have created two Business Relationship Management analyst positions to help support Transmission & Distribution and Customer Service. These two departments rely significantly on well-functioning IT systems. The more we can work closely with departments and know exactly what they need and why, the better we can serve them.

PGE will need three positions to, 1) provide support for ongoing infrastructure fitness evaluation, 2) a software asset manager to monitor compliance with software license agreements, and 3) a Service Level Manager to ensure we continue to provide an appropriate level of service enterprise-wide. The remaining two OCIO positions, which are fully discussed in PGE Exhibit 502, are needed to support our expanding IT systems to maintain and keep the systems operating consistently while minimizing down time.

<u>2. IT Infrastructure</u>

Q. Please describe the nine new positions in IT Infrastructure.

A. Similar to our need for expanded application support, we are requesting four FTEs to provide 24/7 support at our data center operations. We operate our business 24/7 and it is important that we respond to our employees and customers in a timely manner. For example, customers could be directly impacted if crews are unsure of their next work order due to system constraints. During a major outage, we need our computer systems operating and interfacing to deliver the information needed at the time we need it. As we implement these complex, enterprise-wide applications and integrated systems, 24/7 monitoring is required.

In addition, four FTEs are needed to continue providing adequate support to existing and new technologies (i.e., Citrix, Virtual Desktop) and other network equipment that support key applications (i.e., Maximo, OMS, GIS) and interfaces between them. IT is currently limited in the amount of support we provide to these critical systems. The remaining position is for eastside IT support; there are limited qualified contractors available in rural areas and travel time from Portland can be time consuming.

3. IT Risk Management

Q. Please explain the two positions needed for risk management.

A. The continued expansion and complexity of our systems is driving an increasing need for regulatory and compliance support. The two positions needed for risk management are distributed to two main functions: 1) ongoing administration of PGE's newly developed IT Governance Risk and Compliance (GRC) toolset; and, 2) management of the growing IT Compliance and Disaster Recovery departments. This work is expected to be ongoing and integral to our operations, and therefore it is appropriate for the work to be performed by employees, not contractors.

4. Applications Support

Q. Please explain why you need four new positions for applications support.

A. As mentioned above, PGE has significantly reduced the number of applications supported by IT, however, these new enterprise applications are far more complex and have greater functionality. Hence, as we expand the functionality of these systems, PGE needs more personnel to provide ongoing support. These positions are to support MMS, GIS, OMS and PeopleSoft. This work is expected to be ongoing and integral to our operations, and is appropriate for the work to be performed by employees, not contractors.

5. Information Security Program

Q. What progress have you made addressing your Information Security Roadmap since your last general rate case?

A. Since our last general rate case, PGE has been developing and evaluating the next steps to our Information Security Roadmap.[4] To assist in that effort, PGE hired outside consultants to perform a comprehensive review of our information security program. One of the primary recommendations by the consultants was a centralized, enterprise-wide security operations center with detailed steps to achieve that goal. PGE also updated its Information Security Roadmap to address the full scope of their recommendations. These initiatives and their implementation are discussed in Section IV below.

6. Hardware/Software Maintenance Agreements

Q. By how much do software and hardware maintenance agreement costs increase based on current planned projects?

A. From 2016 to 2018, these costs will increase by approximately $4.9 million.

Q. Why are software and hardware maintenance agreements necessary?

A. These agreements are necessary to:

1) Keep our software operational by having access to fixes and patches provided by the vendor;
2) Enable us to obtain and retain appropriate licenses, since some vendors require the purchase of maintenance services as a condition of the software license; and

[4] This was previously referred to as the Cyber Security Roadmap but has evolved and been renamed.

3) Receive regular upgrades to correct programming errors and provide continued technical maturity.

PGE must provide care and maintenance for our technology investment, which extends the useful life of our systems and provides the best value for customers.

Q. In previous rate cases, you stated that the 2020 Vision program was intended to replace numerous applications with fewer enterprise systems. If you have fewer systems replacing numerous applications, why would PGE's maintenance agreement costs increase because of projects such as these?

A. As we decrease the number of applications through consolidation, we see an increase in the maintenance costs associated with either: 1) new and more effective enterprise applications, or 2) expanded use of existing applications (which is especially pronounced as we replace homegrown software, which requires no maintenance expense other than internal labor to provide support). These expanded and new replacement applications are greater in size and complexity because they are enterprise applications that provide greater functionality than the systems they are replacing, and the maintenance is typically more expensive.

Q. What are the primary reasons for the increase in hardware and software maintenance costs?

A. O&M costs for maintenance agreements on hardware and software tend to increase annually for the following reasons:

- Price escalation for maintenance services;
- Implementing new applications to meet new or changing requirements; and
- Replacing obsolete systems with more effective systems that deliver greater functionality, but are more complex than the old systems. In such instances, the new

systems increase efficiency by eliminating certain manual processes and/or by meeting new requirements that the old system could not address.

In other words, increases in the IT operational budget are indicative of purchasing new technologies or expanding the usage of existing technologies. We negotiated maintenance agreements that captured value and we have reduced costs in theses area by volume purchases with a few vendors.

Q. What types of new or expanded systems are you implementing?

A. Examples of new or expanded technologies include:

- A new Residential Energy Analysis Program (Opower) as provided by Oracle;
- Oracle customer care software for the new CET projects;
- New software for hosting the Western EIM system as discussed in PGE Exhibit 400;
- An increase in Office 365 (i.e., a cloud version of email) service fees plus additional deployment of Microsoft software. PGE has moved to the cloud because it is the most effective strategy to maximize functionality and speed. Eventually, the only choice will be cloud email services; PGE is following its fellow utilities in making this change;
- Increased cyber security monitoring and assessment tools including network analysis, threat monitoring, and security testing and analysis;
- Additional investments in outside vendors, such as Gigamon and NetScout[5], for systems and network monitoring;

[5] Gigamon is a technology vendor that provides network visibility and traffic monitoring. NetScout provides application and network performance management products.

- Planned expansion of process intelligence (PI) software[6] for energy asset monitoring and analysis;
- Increased deployment of our security event and incident management tool; and
- New software to support better internal control monitoring.

Q. What are other sources of cost increases from 2016 to 2018?

A. Increases in non-labor costs are due to hardware/software maintenance agreements, which are becoming numerous, and use of contractors or outside services. PGE will still have to rely on contractors for some of the work that we have planned during 2017 and 2018. We emphasize the great complexity of supporting our new systems and the need to protect those systems from numerous cyber threats experienced daily by individuals, corporations, and governments. The threat is real and must be addressed, which will require both labor and non-labor support. Contract labor may have been appropriate in previous years as we built our system. Now that these systems are coming online, it is appropriate for regular employees to learn the systems and support them going forward. Although contract labor is increasing, it would have been greater if not for the shift to regular FTEs.

[6] Process intelligence software can help an organization improve process management by monitoring and analyzing processes on a historic or real-time basis. Process intelligence uses data that has been systematically collected to analyze the individual steps within a business process or operational workflow.

IV. Information Security Program

Q. How is PGE addressing the increasing threats related to cyber security?

A. During 2016, PGE conducted an external review of its Information Security Program (ISP). While PGE had spent significant effort and expense in increasing its security capabilities in recent years, the intent was to ensure that PGE was keeping abreast of increasing cyber threats and corresponding best practices to prevent those threats from circumventing PGE systems. PGE works with many outside parties including other utilities, third-party security experts, industry security groups and others to monitor threats to the electric sector. We are concerned with the increase in scope and severity of recent cyber-attacks on America's critical electronic networks and it is necessary that we take steps now to maintain the security, reliability, and safety of our systems. It is PGE's responsibility to protect the security of our computers, control systems, and other cyber assets that help operate the grid from cyber vulnerabilities.

Q. Isn't PGE already responding to cyber security threats?

A. Yes. PGE has a rigorous program in place to protect critical infrastructure. Our primary focus has been on corporate systems, such as financial and customer systems, as this was where attacks were targeted in the past. However, we are seeing a significant shift in the industry. Operational Technologies (OT),[7] SCADA systems, substation equipment and generating plants are quickly becoming potential targets as threats become more sophisticated and complex. Attacks are frequently occurring when system monitoring is at its lowest, such as nights and weekends. It is becoming even more critical to protect the

[7] OT refers to operational technology or the use of computers to detect or cause a change through the direct monitoring and/or control of physical devices, process and events in the enterprise. http://www.gartner.com/it-glossary/operational-technology-ot/

safety of our system from exploitation, compromise, or attack (both physical locations and electronic breaches) as our system relies more and more on technology. PGE's current program needs to expand its focus to equally protect OT systems and do so on a 24/7 basis.

Q. Please provide some examples of threats that may impact PGE operations.

A. The following two examples serve to emphasize the nature of these threats:

- A recent cyber security incident in Ukraine[8] points to, 1) the need for vigilance and awareness among all users to prevent social engineering threats; 2) the importance of securing OT networks; and 3) the importance of 24-hour monitoring of critical networks.[9]
- National Public Radio featured a story in October[10] about a corporation that experienced a major, complex hacking attack commonly referred to as "distributed denial of service" attack, and security experts see these kinds of attacks all the time. They happen when hackers take over several computers and infect them with malicious software and then use them to barrage a website or a web service with fake traffic until the website/web service stops functioning under this overwhelming demand. This type of attack points to, 1) the creativity with which attackers exploit new technology; 2) the need to not just consider conventional "IT" networks but also non-traditional operational technology devices; and 3) again, the need for 24/7 monitoring.

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[8] http://abcnews.go.com/International/ukraine-conflict-monitor-osce-confirms-cyber-attack/story?id=44430311
[9] Threats can lurk undetected for weeks or months and then suddenly be deployed in a brief period of time.
[10] http://www.npr.org/2016/10/22/498954197/internet-outage-update-internet-of-things-hacking-attack-led-to-outage-of-popula

Q. What were the results of this review?

A. The review affirmed the many things PGE is doing correctly and identified additional security measures to address by successfully executing certain multi-year, enterprise-wide cyber security initiatives. After analyzing these gaps, PGE incorporated these recommendations into our existing multi-year Information Security Roadmap to address the findings of the study that includes several initiatives. Each of these initiatives makes up a series of projects to achieve the full value of the initiative. Projects are a blend of capital assets and operating improvements.

Q. When will PGE implement these initiatives?

A. The primary implementation of these initiatives will begin in 2017 and continue through 2021.

Q. Please briefly describe these initiatives.

A. Based on the potential impact of identified risks, PGE identified the following ten key initiatives:

- Integrated Security Operations Center (ISOC) – Execute a multi-phase initiative to perform proper analysis, planning and coordination to determine the appropriate scope and maturity level for the capabilities of an enterprise-wide ISOC.
- Identity and Access Management (IAM) – Improve PGE's identity and access management governance including processes and tools to establish, extend or improve key service capabilities across the enterprise including user access lifecycle management, access management, and use of role-based access controls.
- Risk Based Governance – Improve executive leadership's control and visibility into enterprise-wide cybersecurity risks in order to comprehensively manage cyber threats

to acceptable tolerance levels. Strengthen partnership through jointly defined roles and responsibilities for collaboration and decision making involving executive management.

- Incident Response – Define and develop an enterprise-wide incident response process and plan to efficiently and effectively respond to future potential incidents.
- Business Impact Analysis (BIA) – Perform planning to update previous processes and procedures to assess and prioritize critical PGE business functions and processes based on the identification of potential business interruption risks and impacts.
- Vendor third-party management – Enhance relationship between security and procurement by applying security focused, risk-based vendor/third-party management concepts at each stage of the vendor/third-party management lifecycle.
- Architecture – Plan for and implement a security architecture function across PGE.
- Vulnerability Management – Develop comprehensive vulnerability management program that covers all assets and adequately detects and reports vulnerabilities in PGE assets to best identify risk.
- Security Awareness and Training – Strengthen and enhance an enterprise-wide security awareness program for all employees, and conduct targeted training for security staff.
- Data Protection – Enhance existing data classification and data protection policies and implement an enforcement mechanism to strengthen data loss prevention.

The list above is not presented in any specific order. Each initiative represents multiple projects that align with one or more of the study's recommendations and PGE's goals.

Q. What activities does PGE plan during 2017 and 2018 to support the initiatives?

A. PGE's 2017/2018 plans include multiple initiatives as identified by PGE and the study. These initiatives are designed to: 1) establish appropriate governance, policies, procedures, and processes to support effective investment in security tools; and, 2) follow-up with design and development of assets required to support those processes.

The majority of 2017 work includes the design and initial development stages of a 24/7 ISOC, and the development of an IAM solution set. Other activities include process enhancements and staffing to support improved third-party risk management, security architecture and design, and incident response.

In 2018, activities focus on the completion of the ISOC and continued phased deployment of IAM solutions, including expansion into field technologies and Role-Based Access Control (RBAC).

Q. How many FTEs will you require in 2017 and 2018 for these activities?

A. PGE is expecting to hire 22 FTEs during 2017 and 2018. PGE Exhibit 502 describes the FTEs in detail.

Q. Please explain why you need 22 FTE to implement the ISP.

A. PGE has evaluated the labor efforts and support required to implement the necessary security initiatives at 22 FTEs. The ISOC will be staffed 24/7 and will require nine FTEs. Their function will be to perform security monitoring, system administration, configuration, event response, threat response and incident response on an enterprise-wide basis. The impact of security threats is no longer just for basic IT systems, but must expand to cover the entire enterprise.

Five FTEs are required to implement IAM, a key initiative, which will help improve and maintain PGE's identity and access management governance, including processes and tools to establish, extend or improve key service capabilities across the enterprise. With all the new applications and software being implemented, security and authorized access needs to be established. In parallel, we will be implementing additional controls such as automated password vaulting, rotation, and monitoring to high risk accounts.

We are increasing four FTEs for security testing, third-party risk management, threat analysis, and design architecture to ensure the integrity of our systems. The security breaches that occurred at both Target[11] and Home Depot[12] involved third-party (vendors) access to systems. In addition, two FTEs (one manager, one administrative) are needed to supervise compliance, security, operations and strategic planning personnel. This consolidates employees critical to security efforts into one department. The remaining two FTEs focus on overseeing the overall implementation of the Information Security Roadmap, which consists of roughly 40 projects over five years.

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[11] http://krebsonsecurity.com/2014/02/target-hackers-broke-in-via-hvac-company/
[12] https://www.infosecurity-magazine.com/news/home-depot-breach-third-party/

V. Qualifications

Q. Mr. Henderson, please provide your qualifications.

A. As Vice President of PGE for Information Technology, I am responsible for the infrastructure, operations and system development of all information systems. This includes developing a strategic plan for information technology and implementing enhanced project management and methodology. I joined PGE in 2005 after serving as Chief Information Officer at Stockamp & Associates since 2003. Previously, I spent eight years as senior IT manager for Willamette Industries, Inc. and was Vice President and Chief Information Officer for four years. I received a bachelor's degree in management from Harding University in Searcy, Ark., and an MBA from the University of Texas. I am also a Certified Public Accountant in Oregon (inactive status).

Q. Mr. Hosseini, please provide your qualifications.

A. I earned a Bachelor's degree in Finance and MBA from Portland State University, where I teach courses in Management, Finance, and Information Technology. I have also taught Management and Human Resources courses for the University of Phoenix and the Utility Management Certificate course for Willamette University. I currently work as the Director of the Office of the Chief Information Officer. Prior to this, I held leadership positions in the Human Resources, Organizational Development, Finance and Accounting, Business Decision Support, and Distribution departments at PGE. Additional experience includes retail sales management, restaurant management, as well as consulting work for a variety of clients.

Q. Mr. Anderson, please provide your qualifications.

A. As Director of Information Security, I am responsible for management and direction of PGE's Information Security Program and the operational oversight of its Information Risk Management department including security assurance, IT CIP Operations, disaster recovery and compliance functions. This includes the responsibility for securing all PGE technology based assets and environments and working with other experts in the security field to design and support industry best practices. I earned a Bachelor's degree in Information Systems from Utah State. My extensive background in security, compliance and risk management have supported the continuing evolution of security practices at PGE. I have more than 20 years of security experience and maintain numerous industry certifications in security management, risk management, forensics, auditing and various technical functions.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
501	Summary of IT Costs by Operating Area
502	IT FTEs - Description of Need

IT Summary by Operating Area

Function	2014 Actuals	2015 Actuals	2016 Actuals	2017 Budget	2018 Forecast	2018-2016 Delta	Annual % Delta 2018-2016
Production							
Assigned	333,366	264	254	-	-	(254)	-100.0%
Allocated	6,695,618	7,264,124	9,557,999	8,827,113	11,069,073	1,511,074	7.6%
Assigned Adjustments					(353,906)	(353,906)	
IT Deferral	(1,251,885)	312,972	312,972	312,971	312,971	(0)	
Total Production	5,777,098	7,577,359	9,871,224	9,140,084	11,028,138	1,156,914	5.7%
Power Operations							
Assigned	462,192	1,022,349	1,011,868	1,617,246	2,164,340	1,152,472	46.3%
Allocated	1,610,682	1,772,266	1,492,874	1,150,370	1,439,973	(52,901)	-1.8%
Assigned Adjustments					-	-	
IT Deferral	-	-	-	-	-	-	
Total Power Ops	2,072,875	2,794,615	2,504,742	2,767,616	3,604,313	1,099,571	20.0%
Transmission							
Assigned	323,714	301,316	595,346	807,480	935,139	339,792	25.3%
Allocated	1,415,835	1,470,604	1,407,217	1,168,727	1,462,951	55,734	2.0%
Assigned Adjustments					(39,761)	(39,761)	
IT Deferral	(224,394)	56,099	56,099	56,099	56,099	0	
Total Transmission	1,515,155	1,828,018	2,058,662	2,032,305	2,414,427	355,765	8.3%
Distribution							
Assigned	732,596	981,509	3,388,577	3,728,055	4,564,270	1,175,693	16.1%
Allocated	16,563,746	17,722,661	20,826,809	23,252,158	29,105,827	8,279,018	18.2%
Assigned Adjustments					(525,650)	(525,650)	
IT Deferral	(1,661,770)	415,443	415,443	415,443	415,443	0	
Total Distribution	15,634,572	19,119,613	24,630,829	27,395,656	33,559,890	8,929,062	16.7%
Customer Acctg/Svc							
Assigned	2,518,166	3,742,323	2,751,874	4,196,604	7,536,379	4,784,505	65.5%
Allocated	13,321,027	13,434,747	14,072,169	14,104,269	17,654,982	3,582,814	12.0%
Assigned Adjustments					(509,012)	(509,012)	
IT Deferral	(2,109,865)	527,466	527,466	527,466	527,466	(0)	
Total Customer Acctg/Svc	13,729,329	17,704,536	17,351,509	18,828,339	25,209,815	7,858,306	20.5%
A&G							
Assigned	4,358,145	4,622,875	4,523,496	5,140,231	5,536,900	1,013,404	10.6%
Allocated	9,774,225	10,565,799	11,975,293	11,056,225	13,771,155	1,795,863	7.2%
Assigned Adjustments					(289,305)	(289,305)	
IT Deferral	(1,699,285)	424,821	424,821	424,821	424,821	(0)	
Total A&G	12,433,086	15,613,495	16,923,610	16,621,277	19,443,571	2,519,961	7.2%
Totals							
Assigned	8,728,180	10,670,636	12,271,415	15,489,616	20,737,027	8,465,612	30.0%
Allocated	49,381,133	52,230,200	59,332,360	59,558,861	74,503,961	15,171,601	12.1%
Assigned Adjustments	-	-	-	-	(1,717,634)	(1,717,634)	
IT Deferral	(6,947,200)	1,736,800	1,736,800	1,736,800	1,736,800	(0)	
Totals by Operating Area	51,162,113	64,637,636	73,340,575	76,785,277	95,260,154	21,919,579	14.0%
Labor Adjustment				(839,747)	(863,355)		
Adjusted Grand Total	51,162,113	64,637,636	73,340,575	75,945,530	94,396,799	21,056,224	13.5%
Control	-	-	-	-	-	-	

Title	FTE	2016-2018 Incremental FTE – Description of Need
IT - GENERAL		
Office of Chief Information Officer (OCIO)		
IT Business Relationship Management Analyst – T&D	1	Analyst to support T&Ds planning and execution of IT initiatives. Includes roadmap development, project proposals and intake, and issue resolution. The technology needs across T&D continue to grow each year. Aligning all of this work with IT, prioritizing, ensuring timely issue resolution are all critical to the successful implementation and support of T&Ds technology solutions. Work has been allocated across multiple resources, but this is causing growing priority and alignment issues.
IT Business Relationship Management Analyst, Customer Service and Delivery	1	Analyst to support Customer Service and Delivery planning and execution of IT initiatives. Includes roadmap development, project proposals and intake, and issue resolution. The demand for new technology that supports our customer's needs continues to grow each year. Aligning this work with IT, prioritizing, ensuring timely issue resolution are all critical to the successful implementation and support of our customers.
Business Analyst	1	Support the ongoing Infrastructure Fitness evaluation for replacement and growth of infrastructure equipment used to support IT systems. Currently we fill this position with a contractor and since this is an ongoing project the cost to the company would be less if filled with an FTE.
Software Asset Manager	1	Responsible for reviewing and maintaining software license compliance over the IT portfolio. A dedicated resource to review and coordinate compliance will reduce the risk of compliance issues moving forward and license and maintenance optimization may further reduce IT maintenance expenses. Today this role is spread across all IT operating functions which complicates compliance activities, increases compliance risk and increases license compliance costs.
Service Level Manager	1	Responsible for managing IT Service Levels and Continuous Service Improvement. As the IT organization transitions from a technology provider to a service provider additional emphasis is required to identify, measure and improve service delivery.

Analyst, Business and Design, EIM	2	Entrance into the EIM introduces several new applications and new interfaces to existing applications. The large addition of new software solutions increases the support load required from the OCIO IT Energy Systems team. To meet this increased demand an additional Business Analyst and Developer Analyst are required. Many of the new applications require 24/7 support. This high availability will require the IT Energy Systems team to cover more systems during the usual off hours placing greater strain on capabilities of a relatively small team.
Infrastructure		
Specialist IV, Technical	1	Support for eastside generation facilities to perform technical support. There is currently less on-site support for generation sites on the eastside. Given the distance from Portland, techs are only sent out as needed or on infrequent rotation leaving a gap. Contractors have been considered, but adequately trained individuals are difficult to find in rural locations. This will be a long-term, ongoing need.
System Analyst III, 24/7 Operations in Data Center	4	The requirements for 24/7 support of our data center is driven by high availability requirements of (2020 Vision) key line of business application implementation that are highly integrated and automated across various IT systems. If systems go down on the weekend or in the middle of the night, IT needs to be available immediately to help resolve the issue, especially if this occurs during an outage event, which could directly impact customers.
System Analyst III, Citrix Support	1	PGE's Outage Management System and virtual desktop architecture for our call center are delivered from a Citrix environment. Infrastructure team currently is limited in number of FTE to provide adequate Citrix support to the business.
System Analyst IV, TCC IVT Support	1	To provide adequate support of PGE's Call Center Technology additional Cisco Networking expertise is required. This is mainly driven by a very complex and integrated solution stack that is comprised of several technology domain.
Specialist	1	Provides support for IT Infrastructure. Increased number of critical applications that require faster response to infrastructure issues (i.e., OMS, GIS, Maximo). Additional staff needed to increase on-site staffing model beyond 40 hours per week, and provide more resources to respond to issues after normal business hours.
Design Build Specialist	1	Increased complexity of systems and the need to automate more of the build process. Many architecture design enhancements not covered by capital projects requiring more O&M resources. It is critical to have core resources that are knowledgeable about the PGE IT environment.

Applications		
IT Systems Manager	1	We have invested in several new software products to support cyber security and IT operations. The ongoing maintenance and care of these systems needs to be treated like other software products used by the business. The approach that we have used successfully in the past has been to devote a team dedicated to that line of business to maintain these systems. With the implementation of several new systems in this area, we believe we now have enough work that requires a dedicated team to support them. Most of the people in this team are being reassigned from other teams. The only net new person is a manager to oversee this group.
Quality Assurance Analyst	2	Required to provide quality assurance support for Business Intelligence, GIS, Finance, and Human Resources. The applications supported are complex and require highly skilled QA analysts.
Quality Assurance, Release Manager	1	This position is required to provide Release and Deployment support for IT Applications project and team efforts, currently supported by a mix of both FTE and contractors. Current and future workloads make it clear that present staffing levels will be inadequate to provide the necessary level of accuracy and completeness that Release involvement delivers to the enterprise.
Risk		
Governance Risk Compliance System Support	1	Currently, there are no FTEs assigned to support and administer the GRC tool. When GRC was deployed in 2015, it was expected that support needs would be minimal. However, based on volume of regulatory changes and enhancements in the last 18 months, and the other uses for the tool, PGE has reassessed its need. This position will provide services that are not currently being performed and will reduce the overall vendor spend for the support of the applications. The GRC tool provides increase automation and notification of compliance requirements and workflows.
Compliance Manager	1	Management over the growing IT compliance and disaster recovery departments. This manager will oversee 5-8 FTE plus 2-3 contingent workers. Provide increased oversight on IT compliance and risk directives.
TOTAL IT FTEs	**22**	

INFORMATION SECURITY PROGRAM		
Security Assurance		
ANALYST IV,SR Information Security	2	These roles will provide security testing of PGE systems traditionally performed by contractors to ensure PGE systems are configured and maintained in a secure fashion. Contractor testing is less efficient and more costly than internal staff. This work has been performed by 4-5 contractors.
Analyst IV, Security Assurance	1	This analyst will perform third-party risk management, contracts and vendor testing.
Analyst IV, Threat Analyst	1	This role develops and performs the threat management function. He/she focuses on the identification, analysis and response to new and emerging threats.
Information Security Operations Center (ISOC)		
Manager, ISOC	1	New manager identified by outside consultant study for newly defined team based on executive request for enterprise security operations group to be developed.
Analyst, ISOC	5	Staff of newly identified and newly developed 24/7 ISOC. ISOC functions to include security monitoring, system administration, configuration, event response, threat response and incident response. ISOC coverage to expand from basic IT to enterprise IT and OT.
Spec V, Security Monitoring	1	This role serves as liaison and support between corporate security and cyber security as it relates to 24/7 Incident Response as part of new ISOC.
Specialist, ISOC, T&D	2	Staff of newly identified and newly developed 24/7 ISOC. ISOC functions to include security monitoring, system administration, configuration, event response, threat response and incident response. ISOC coverage to expand from basic IT to enterprise IT and Operational Technologies (OT). Specialist focused and trained on T&D OT systems.

Identity Access Management (IAM)		
Analyst IV, Applications Developer	2	Combined developers, administrator and quality assurance analysts assigned to the development, support, administration and code testing for Password Vault, IAM, and other access tools.
Analyst IV, Role Manager, RBAC	1	Process manager required to design, develop and support ongoing Role Based Access Control, permissions and governance.
Analyst IV, Governance, Access & Reporting	1	Compliance Analyst required to support ongoing access governance, reporting and system design for multiple regulations including SOX, CIP and HIPAA
Analyst III, Identity/Access Bus Analyst	1	Analyst to support the planning, design, requirements and documentation of projects associated with capital investment. (roughly 14 projects over 5 years)
Information Security Roadmap		
Program Manager, ISP	1	Program Manager will lead/facilitate the design, development and implementation of this multi-year information security program roadmap. Oversee budgets, planning, schedules and multiple project managers.
Analyst IV, Program Bus Analyst	1	Analyst to support the design, requirements and documentation management of roadmap projects not associated with capital investment (roughly 40 projects over 5 years)
T&D/Security		
Manager, T&D OT Support Services	1	Manager to supervise compliance, security, operations and strategic planning personnel. This consolidates employees critical to security efforts into one department and allows the General Manager to dedicate 25% of time to Security leadership.
Admin, T&D Substation Support	1	Admin assistant to coordinate documentation, meetings, manager schedules and action items associated with Security efforts. This additional support ensures the General Manager of Substation OT is able to dedicate 25% of time to Security leadership.
Total ISP FTEs	**22**	
Total IT FTEs	**44**	

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Corporate Support

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Jim Lobdell
Alex Tooman, Ph. D.

February 28, 2017

Table of Contents

I. Introduction

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

A. My name is Jim Lobdell. I am the Senior Vice President, Finance, Chief Financial Officer, and Treasurer at PGE. My qualifications appear at the end of PGE Exhibit 100.

My name is Alex Tooman. I am a Project Manager for 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 $172.1 million in administrative and general (A&G) costs in 2018 and compare it to 2016 actuals of $170.9 million.

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

A. We classify as A&G those functions that support PGE's direct operations to deliver electric power to customers, such as human resources, accounting and finance, insurance, contract services and purchasing, corporate security, 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 FERC definition of A&G.[1] PGE Exhibit 601 provides a list of A&G functions plus a summary of costs and full time equivalent (FTE) employees for 2014 (actuals) through 2018 (test year forecast). Table 1 below summarizes the major A&G costs 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	2016 Actuals	2018 Forecast	Delta*
Facilities	$5.5	$7.0	$1.5
Accounting/Finance/Tax	$9.9	$11.3	$1.4
HR/Employee Support	$9.8	$13.4	$3.6
Insurance, Injuries and Damages, etc.	$11.5	$12.2	$0.8
Legal	$10.0	$5.4	($4.6)
Regulatory Affairs/Compliance	$2.6	$3.4	$0.8
Corporate Governance	$4.6	$5.4	$0.8
Business Support Services	$2.4	$2.8	$0.3
Environmental Programs	$4.4	$2.2	($2.1)
Corporate R&D	$2.0	$3.0	$1.0
Contract Services/Purchasing	$1.4	$1.4	$0.0
Security and Business Continuity	$2.2	$2.9	$0.7
Corp Communications/Public Affairs	$2.2	$2.4	$0.2
Load Research	$0.1	$0.0	($0.1)
Hydro Licensing	$0.1	$0.1	$0.0
Performance Management	$1.3	$2.1	$0.8
Governmental Affairs	$1.2	$1.2	$0.0
Total for Major Functional Areas*	**$71.0**	**$76.3**	**$5.2**
IT: Direct and Allocated	$12.1	$13.4	$1.3
Labor Cost Adjustment	$0.0	($3.6)	($3.6)
Membership Costs	$3.1	$3.6	$0.5
Incentive Plans (net of capital allocations)	$21.6	$12.6	($9.0)
Severance	$1.6	$1.3	($0.3)
Regulatory Fees	$6.7	$8.7	$2.0
General Plant Maintenance	$2.6	$2.9	$0.3
Net PTO	$4.4	$6.3	$2.0
Net Loadings	$0.0	$0.0	$0.0
Benefits (net of capital allocations)	$51.8	$57.7	$5.9
Corporate Allocations	($5.7)	($8.7)	($3.0)
Revolver Fees, Margin Net Int., Broker Fees	$1.9	$1.8	($0.1)
Total Other A&G Costs*	**$99.9**	**$95.8**	**($4.1)**
Total A&G*	**$170.9**	**$172.1**	**$1.2**

** May not sum due to rounding.*

Q. What are the primary drivers for the increase in A&G costs from 2016 to 2018?

A. Most of the increases in A&G costs from 2016 to 2018 are attributable to three primary drivers: 1) Benefits, as discussed in PGE Exhibit 400, are largely driven by health care costs. 2) Security and emergency management, driven by the growing recognition of the potential for detrimental events and PGE's and our regulating bodies increasing emphasis on protecting critical energy infrastructure. 3) Human Resources, driven by PGE's continued efforts to reduce workplace injuries and move to best in class in workplace safety, along with increased demands on PGE's staffing and training departments. While we can and do actively manage costs associated with these drivers, they are, to some extent, external to PGE and reflect larger market conditions and/or regulatory requirements beyond our control.

Q. Will you be discussing any additional A&G related items?

A. Yes. In addition to the drivers highlighted above, we will discuss the following:

- Costs associated with PGE's corporate research and development (R&D) activities;
- Increasing membership costs for PGE's participation in the Western Electricity Coordinating Council (WECC) and the Northern Tier Transmission Group;
- Increases in labor and outside services for Accounting and Finance Services;
- The current insurance environment, as prudent insurance coverage is integral to PGE's operations; and
- PGE's forecast of A&G related environmental costs and their relationship to PGE's pending Environmental Remediation Costs Recovery Adjustment, PGE Tariff Schedule 149, (Docket No. UM 1789).

Q. How is the remainder of your testimony organized?

A. After this section, we have four sections:

- Section II: Primary A&G Cost Increases;
- Section III: Other Items;
- Section IV: Environmental and Licensing Services; and
- Section V: Summary.

II. Primary A&G Cost Increases

A. Benefits

Q. By how much do you forecast benefit costs to increase from 2016 to 2018?

A. The increase in net benefit costs from 2016 to 2018 is approximately $5.9 million. These costs include such items as health and dental plans, 401(k) plan, pension costs, and employee life and disability insurance.

Q. What accounts for this increase?

A. The primary driver of the increase in benefit costs is health-care costs, which reflect inflation and other cost pressures. PGE Exhibit 400 explains in greater detail how the compensation and benefits-related costs are affected by these increases and how PGE must address them to remain competitive in a market for specialized and qualified labor. Please note that the benefit amounts in Table 1 above represent the "net" changes within A&G.[2] PGE Exhibit 400 explains the gross corporate forecast for these costs.

B. Security and Emergency Management

Q. Please explain the cost increase for Business Continuity and Emergency Management (BCEM) and Security.

A. PGE's costs for BCEM are forecasted to increase from approximately $0.8 million to $1.2 million from 2016 to 2018, while security costs are expected to increase from approximately $1.4 million to $1.7 million over the same period. As discussed in PGE's 2016 general rate case (UE 294, Exhibit 600), the projected increase to BCEM costs is based on the continued development and completion of a BCEM roadmap. The roadmap establishes the activities PGE needs to perform to achieve a target level of regional

[2] Net A&G refers to the amount remaining in A&G after labor loadings apply certain amounts of these costs to capital projects, service providers, and "below-the-line" activities.

preparedness and resilience among PGE's primary departments/systems. The increase to security costs is due largely to increasing regulation and the expanding footprint of PGE's physical locations.

Q. What is the history and purpose of the BCEM department?

A. 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 to recover critical functions as quickly as possible, 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. You stated that PGE needs to meet a "target level of resilience". Please explain.

A. Resilience is the ability of a department to quickly restore its performance to an operational level after some form of detrimental event. By detrimental event, we are referring to natural events (e.g., major earthquake or flood), technological events (e.g., a significant system or plant failure due to mechanical or physical issues), or man-made (accidental or intentional) events (e.g., a successful cyber-attack or act of terrorism). In order to evaluate a department's resilience, the BCEM roadmap establishes a timeline for each primary department/system to undergo the following cycle:

- Develop plans to restore operations;
- Train employees on restoration procedures;

- Perform exercises to test employees; and
- Evaluate performance.

Once established, this cycle is an annual mechanism that will continue to strengthen PGE's capacities and capabilities for emergency response.

Q. Has PGE expanded its corporate resiliency and emergency preparedness efforts?

A. Yes. Through 2014, BCEM operated with only four or less FTEs (with approximately two of these FTEs for support and administration). This limited the number of areas within PGE that BCEM was able to support with its full range of duties. As the awareness of and potential for detrimental events continue to increase, PGE continues to expand its BCEM efforts. To this end, we hired three additional FTEs between 2015 and 2016 to help with the company-wide implementation of key initiatives established in the BCEM roadmap. For 2017 and 2018, BCEM is increasing outside services support in order to continue our efforts in meeting the annual elements identified within the roadmap's timeline. This effort is also based in part on The Oregon Resilience Plan,[3] which recommends that "Energy sector companies should institutionalize long-term seismic mitigation programs and should work with the appropriate oversight authority to further improve the resilience and operational reliability of their Critical Energy Infrastructure (CEI) facilities" (page 175).[4]

Q. What are some recent activities in which PGE's BCEM department has been involved to further PGE's corporate resiliency and emergency preparedness?

A. PGE was very active during 2016 in efforts to assess our corporate resiliency and emergency responsiveness to a Cascadia Subduction Zone earthquake and tsunami. In particular, PGE

[3] Issued by the Oregon Seismic Safety Policy Advisory Commission to the Oregon State Legislature in February 2013.
[4] The Oregon Resilience Plan is available at: http://www.oregon.gov/OMD/OEM/osspac/docs/Oregon_Resilience_Plan_Final.pdf

participated in the U.S. Department of Energy's Clear Path IV exercise and closely followed the region-wide Cascadia Rising 2016 functional exercise. Based on these exercises, the BCEM team plans to expand its core planning related to regional disasters, with improvements to fueling, staging and communications.

Q. Please describe the reasons for increasing security costs.

A. PGE's security costs are increasing due primarily to the expanding footprint of PGE's system and the addition of new regulations affecting some of PGE's substations. Recent and upcoming additions to PGE's footprint include two new plants at the end of 2014, Carty in 2016, and a number of smaller substation projects that will be completed over the next one to two years. Additionally, Critical Infrastructure Protection regulation 014-1 (CIP-14) has directed PGE to employ higher security measures at several of its transmission substations that "if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection."[5]

Q. What other trends are putting increased pressure on Corporate Security?

A. As Portland's homeless population has grown, PGE is seeing a significant increase in homeless camps in and around PGE facilities, most notably at or near PGE substations. Consequently, PGE's Corporate Security employees are responding to an increased volume of safety and security concerns related to these camps. PGE's current security staff cannot continue to meet the demands of this increased volume in a consistent manner.

Q. How is PGE addressing these issues?

A. In order to provide effective security coverage for our expanding footprint of assets, and to address the increased security concerns from our community, PGE is adding three FTEs between 2017 and 2018. One additional FTE will be hired to provide project management

[5] http://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-014-1.pdf

support for CIP-14 and to lead the day-to-day operations of PGE's expanding physical security systems.

C. Human Resources

1. Safety

Q. Please discuss PGE's company-wide safety focus.

A. PGE has been and continues to be committed to providing a safe and healthy place for employees, customers, and the public. Safety is a core value that PGE integrates into everything we do. We believe most hazards can be identified and effectively controlled or eliminated to prevent incidents and their consequences. Thus, it is important that we focus on continuously improving our safety performance, to meet our goal of an injury-free workplace.

Q. Has PGE's safety record shown improvement?

A. Yes. There are a number of signs indicating that PGE's record on safety is improving. Most notably, PGE has seen a decrease in workplace accidents, as evidenced by a 23 percent overall decrease in Occupational Safety and Health Administration (OSHA) "recordable" accidents since 2014.[6]

Q. What additional steps is PGE taking to improve safety?

A. In order to increase the effectiveness of PGE's safety culture and continue to reduce injuries and incidents, PGE has developed a comprehensive five-year safety strategy plan. Additionally we are adding one FTE in 2017 and one FTE in 2018 that will help address the following:

[6] OSHA defines a recordable accident as any work-related injury or illness that causes a fatality, unconsciousness, lost work days, restricted work activity, job transfer or medical care beyond first aid.

- A greater level of support in auditing PGE's safety programs, providing technical writing support and general support of new and existing safety programs and practices;
- Thorough administrative and analytical support of PGE's safety reporting system to harness the system benefits of improved safety metrics analysis, incident reporting, and anonymous "near-miss" reporting;
- Support for an increased level of safety and work practices training; and
- Implementation and increased focus on specialized employee and contractor safety and injury prevention programs, such as:
    a. The MoveSmart program to reduce sprains and strains;
    b. The Early Injury Intervention Effort for preventative self-treatment strategies;
    c. The Safety Leadership Development Program to provide management and safety mentors the tools to promote safe practices; and
    d. The Contractor Safety Program to promote a safety culture throughout PGE's operations.

A copy of the five-year safety strategy map outlining the above activities is included in the work papers for PGE Exhibit 600.

2. Support Services

Q. How much are training and staffing services costs projected to increase for 2018?

A. PGE's costs for these support services are forecasted to increase from approximately $3.6 million to $5.2 million from 2016 to 2018.

Q. Please describe the drivers behind PGE's increase in staffing.

A. PGE continues to see an increase in the volume of hiring, placing increased demands on current staff, who are now operating beyond their capacity. As shown in Table 2 below, the actual and projected number of annual job requisitions staffing services has filled since 2014 is increasing substantially. This current and projected higher level of hiring reduces staffing services effectiveness and cannot be maintained at the current staffing levels. Additionally, with a high number of senior professionals nearing retirement at PGE (and throughout the utility industry), the demands for skilled utility professionals has increased. At the same time, an improved economy has increased the difficulty and time requirements involved to recruit, hire, and retain these in-demand professionals.[7]

Table 2
Filled Position Requisitions

Year	Filled Requisitions
2014	638
2015	838
2016	930
2017*	1,200
2018*	950

*Estimated

Q. Are there other pressures increasing the workload for PGE's Staffing Services?

A. Yes. Along with the pressures associated with the overall increases in hiring, PGE is hiring more PGE employees, rather than outside contractors, for recent capital project work. Specifically, PGE is increasing the level and pace of transmission and distribution (T&D) maintenance and reliability work throughout our system. To perform this work, PGE is relying more on internal PGE labor as opposed to the outside services traditionally used for large-scale generation projects. PGE decided on this strategy primarily due to the scarcity of qualified labor, the high turnover rate of contract labor, and commitment to the projects, which are long-term in nature. However, using more of an internal, rather than external

[7] According to the Bureau of Labor Statistics, as of December 2016, Oregon's unemployment rate was 4.6%. https://www.bls.gov/eag/eag.or.htm#eag_or.f.p

workforce does place additional strain and workload on our Staffing Services department. PGE Exhibits 400 and 800 provide more detail on this hiring strategy.

Q. How is PGE addressing these pressures?

A. To address the increased hiring pressures and maintain recruiting competitiveness, Staffing Services is adding three and a half FTEs between 2017 and 2018. Staffing Services has also increased its budget for outside services to assist with the recruitment process. These additional FTEs will allow Staffing Services to meet the increased demand in hiring, while maintaining its current time-to-fill-ratio. Additionally, Staffing Services will continue supporting management in its selection process and engage in proactive recruiting strategies such as career fairs, data-driven analytics, college internships, line pre-apprenticeship programs, and social media outreach.

Q. How have PGE's training needs changed over the last couple of years?

A. The demands for training continue to increase as PGE continually implements and integrates new systems and programs. At the same time, the electric utility industry continues to evolve, leading to a greater complexity of systems, processes, and regulatory requirements. Due to this complexity, and for program consistency, PGE has begun centralizing the majority of our training programs in order to gain maximum efficiency of effort. This centralization effort also allows PGE's functional area subject matter experts to focus on their job-specific requirements. As such, with this centralization of both instructor-led and computer-based training, PGE's training department is adding three FTEs in 2018 and increasing its contract labor budget. These additional FTEs are in support of the centralization effort along with the following increases to training demands:

- Additional pre-apprenticeship program offerings and continued growth associated with the existing apprenticeship program;
- New curriculum development including: safety leadership, service design management, and soft tissue injury prevention;
- Increasing mandatory regulatory training and development;
- Additional Generation Excellence training;
- New engineer curriculum for Transmission, Distribution and Generation engineers; and
- Company-wide skill track creation and maintenance.

III. Other Items

A. Research and Development

Q. Why does PGE engage in Research and Development (R&D) activities?

A. PGE conducts R&D on behalf of customers to both preserve and improve system reliability and at the same time to anticipate changes that could profoundly alter the grid.

Q. What are PGE's forecasted 2018 costs for PGE's corporate R&D activities?

A. For 2018, we forecast approximately $3.0 million in R&D expenses, of which approximately $2.8 million is for specific R&D projects and the remainder is for administrative expenses. This reflects an increase of approximately $1.0 million over 2016 actuals. PGE's increased spending represents numerous selected projects that will address the significant changes and new technologies facing PGE and the electric industry. These R&D projects primarily relate to Smart Grid (SG) applications, system reliability (SR), renewable power (RP), operational efficiency (OE), energy storage (ES), and system resiliency (SY). These R&D projects directly contribute to PGE's ability to evaluate and deploy technologies and resources that will benefit our customers for decades to come; they help shape Oregon's energy future to conform to customer priorities for an even more reliable, sustainable and smarter electric power system. Table 3 below provides a listing of the 2018 R&D project categories and number of expected projects within each category. We also provide a complete listing with descriptions and project benefits in PGE Exhibit 604.

Table 3
Topical Summary of 2018 R&D Applications

	Category	Approx. Cost	Number of Projects
SG	Smart Grid	$925,300	18
SR	System Reliability	$578,000	10
RP	Renewable Power	$535,000	7
OE	Operational Efficiency	$430,000	7
ES	Energy Storage	$210,000	4
SY	System Resiliency	$75,000	2
	Total	**$2,753,300**	**48**

Q. Please summarize why PGE is requesting an increase in R&D funding.

A. The U.S. electrical grid is aging and changing in very substantial ways. It is increasingly clear that central station power generation and the "one-way" power flow that it fostered will slowly be replaced with distributed forms of power generation, including solar, biomass, small/low head hydrokinetic devices, and wind resources. The arrival of these smaller sources of power generation will by necessity, require "bi-directional" power flow that can emanate from residential and commercial structures and even PGE electrical substations. Smart AC/DC inverters for autonomous control of batteries and distributed generation devices, smart switches capable of sectionalized isolation and heightened concern for cybersecurity will all have important roles going forward. It is important that PGE, for safety and efficient application, understands how this new and substantial transformation will unfold. This means that PGE should study now the possible implications and preparations needed to accommodate industry advances.

Q. What is PGE doing to pursue R&D in a cost effective manner?

A. PGE recently assessed its R&D cost effectiveness using two principal approaches: 1) participation in a nationwide benchmarking study and 2) limiting overhead cost.

Q. Describe the Benchmarking Study results as they pertain to PGE's R&D spending.

A. PGE and 48 utilities voluntarily participated in a 2016 R&D Benchmarking Survey conducted by the Electric Power Research Institute (EPRI). In that study, PGE's annual R&D expenditure of $2 million was the fifth lowest out of the 12 participating western utilities. PGE also ranked below average on a revenue-adjusted basis, when compared to all 48 utilities.[8] On absolute and relative bases, PGE's R&D expenditure is low when compared to western utilities and low on a revenue-normalized basis compared to 48 U.S. utilities.

Q. Describe the Benchmarking Study results as they pertain to R&D administrative costs.

A. PGE limits its overhead costs in pursuing R&D even in the face of increased funding and program efforts. PGE's FTEs for R&D administration have decreased from 1.7 in past years to only 1.0 for 2018. The EPRI R&D benchmarking study showed that for investor owned utilities the average number of R&D FTEs was 1.3. The fact that PGE's FTE levels associated with R&D administration are lower than the utility average validates the efficiency of PGE's R&D program.

Q. Does PGE engage research partners?

A. Yes. PGE leverages many of its R&D projects financially by working with other utilities as well as universities to co-sponsor and/or share R&D. In doing so, PGE and its customers receive 100% of the benefits for a fraction of the overall research costs; often receiving useful knowledge much earlier than if we did not contribute or otherwise engage with research partners. PGE's university partners view PGE's R&D dollar contributions as part of required matching funds for much larger federal or other institutional grants, and would

[8] Out of 48 utilities, PGE ranked 20th from low to high when R&D expense was normalized to revenue, and was about 75% of the overall average of 0.21% of R&D expense as a percent of revenue.

otherwise be unable to receive the necessary funding without PGE's co-sponsorship. PGE will work with several universities on shared projects that support unique, regional renewable power research that include wave, wind, solar, and CO_2 capture, as well as sequestration through torrefied biomass fuel used to displace coal. PGE will continue to co-sponsor projects with Portland State University, Oregon State University, Washington State University, University of Oregon and Oregon Institute of Technology.

Q. How have PGE's customers benefited from R&D in the past?

A. PGE recently completed a 20-year retrospective report covering its R&D activities over the period 1994-2014. An experienced consultant, funded by PGE, performed seven detailed case studies to assess value and benefit to customers. Value determinations involved both operating savings and avoided capital expenditures (netting these against operating costs and capital costs). The net value for these seven case studies were then compared to the base R&D costs that made these projects possible. The comparison showed a $37 to $1 net value over the original R&D cost. PGE's work papers for Exhibit 600 include this 20-year report.

Q. What is PGE's plan for 2018 Smart Grid projects?

A. PGE has identified 48 total projects for 2018 of which 18 relate to Smart Grid (or "Integrated Grid") topics. Smart Grid work comprises 38% of the total project numbers and 34% of the 2018 R&D funding request. Of the 18 Smart Grid projects, 12 are primarily on the behalf of residential and commercial customers. This is timely due to the influx of electrical devices that are rapidly becoming "smart" and finding their way into the "internet of things" ecosystem. Examples include more granular and autonomous energy controls at the device level (e.g., water heaters, thermostats, and lighting of all types). The energy control devices, when aggregated appropriately, may be harnessed to benefit the power grid, and thus customers in terms of load shifting and demand response support, which ultimately can lower operational costs.

Q. Please summarize PGE's other 2018 R&D efforts and the reasons behind these efforts.

A. PGE's 2018 R&D effort also supports System Reliability, Renewable Power and Operational Efficiency and these proposed R&D projects are in proportions varying from 15% to 20% of the 2018 R&D effort. System Reliability and Operational Efficiency work focuses on PGE's established infrastructure (e.g., power plants, poles, wires and substations), making it more reliable, safe and efficient. R&D in these areas, especially when coupled with EPRI programs, help PGE to keep abreast of industry best practices and lessons learned in power generation and transmission and distribution areas. PGE R&D projects include twelve EPRI programs, and are part of the 24 projects that form the three areas of interest. Finally, there are four Energy Storage and two System Resiliency projects targeted for 2018 R&D efforts. Due to cost, energy storage options such as batteries continue to hover at the edge of practicality; nonetheless, PGE needs to be aware of advances in this area especially as it relates to system resiliency support in the event of large, disruptive events such as a Cascadia Subduction Zone earthquake. In these types of emergencies, energy storage capability, whether stationary or mobile such as in electric vehicles, can play a meaningful role in recovery and restoration efforts. PGE will continue its efforts to validate use cases for the five MW, 1.25 MWh lithium ion battery inverter system (BIS) at its Salem Smart Power Center. This substantial BIS was highly subsidized by the United States Department of Energy as part of its five-year Pacific NW Smart Grid Demonstration Program of which PGE was a participant from inception.

B. Memberships

Q. Please explain the increase in membership expenses from 2016 to 2018.

A. PGE's membership costs have increased by approximately $475 thousand from 2016 to 2018. This increase is largely attributed to PGE's mandatory participation in WECC and PEAK Reliability (PEAK), projected at $2.3 million in 2018, compared to $2.0 million in 2016.

Q. What process does PGE use to budget for annual WECC and Peak expenses or fees?

A. PGE bases its budget for 2017 and 2018 on the estimated amounts provided to PGE from WECC and PEAK that are included in their annual business plan and budget documents.

Q. What reasons do WECC and PEAK provide for the increased fees?

A. According to annual budget documents, both WECC and PEAK are increasing membership fees due primarily to rising personnel expenses and increases in fixed asset additions.

Q. Have there been any other significant increases in membership costs?

A. Yes. PGE's share of membership in the Northern Tier Transmission Group (NTTG) will increase by approximately $100,000 from 2016 to 2018.

Q. What is the NTTG?

A. The NTTG is comprised of transmission providers and customers that actively purchase and sell transmission capacity on the Northwest and Mountain States grid. The group coordinates individual transmission systems planning of their high-voltage transmission network to meet and improve transmission services that deliver power to customers. NTTG coordinates its planning activities with the three other Regional Transmission organizations in WECC (Columbia Grid, West Connect, and CAISO). PGE participates in the NTTG along with a number of other utilities, transmission owners, and stakeholders in the region.

Q. What reasons does NTTG provide regarding their fee increase?

A. Beginning in 2017, NTTG anticipates a sizable increase in consulting and legal fees regarding potential modifications to Federal Energy Regulatory Commission (FERC) Order No. 1000, which establishes the requirements for transmission planning.[9] NTTG also anticipates increased modeling and analysis to support the development and implementation of the WECC Anchor Data Set (ADS). Benefits of the ADS include establishing a common starting point for all production cost model and power flow datasets, produced by WECC and the Planning Regions, which will result in aligned assumptions used in the planning model development for The Transmission Expansion Planning Policy Committee and the Western Planning Regions.

Q. Has PGE included an adjustment to Memberships in this case?

A. No. In the past PGE has included a pre-filing adjustment to remove costs associated with non-utility memberships and lobbying. However, because these costs are identifiable when PGE is charged for them, PGE now records and budgets for them in applicable, non-utility accounts that are not included in this filing.

C. Accounting and Finance Services

Q. How much are costs in PGE's Accounting and Finance organization projected to increase for 2018?

A. PGE's costs for these services are forecast to increase from approximately $9.9 million to $11.3 million from 2016 to 2018.

Q. Please briefly describe the drivers behind this increase.

A. This increase is due to the addition of four FTEs needed to support various functions in the Accounting and Finance area along with an increase in outside services support.

[9] See https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp for more detail on FERC Order No. 1000.

Q. Why does Accounting and Finance require four additional FTEs?

A. PGE is adding four additional FTEs to help in the following areas:

- Supply Chain – We are adding two FTEs to Supply Chain Services to address the current lack of resources available for supporting increased activity in both purchasing and vendor management activities due to centralization and streamlining of all supply chain functions.
- Accounts Payable/Receivable (AP/AR) – One FTE is being added to the AP/AR department to provide additional compliance support for PGE's purchasing card (P-card) program. After auditing its P-card program, PGE determined that additional oversight was required to improve compliance management and provide timely reviews of expenditures. Doing this will reduce PGE's potential exposure to unauthorized/fraudulent charges. Additionally, compliance responsibilities will increase as PGE increases its ratio of P-card usage versus check or Automated Clearing House transactions, in order to reduce the average per-transaction charge.
- Corporate Finance – We are adding one FTE to provide company-wide Enterprise Risk Management (ERM) support. PGE does not currently have a full-time resource dedicated to ERM activities. This position will work throughout the organization with subject-matter experts to identify and assess particular events or circumstances in terms of their likelihood and magnitude of detrimental impact to PGE. The next steps after identification are to develop a response strategy and to monitor future progress.

Q. Why are outside services increasing for Accounting and Finance?

A. The outside services increase is largely attributable to increases in PGE's auditing costs for 2017 and 2018 as compared to 2016. Beginning in 2017, PGE's audit services increased their fees by approximately $100,000. Additionally, PGE is forecasting an increase of approximately $200,000 for additional auditing hours needed to identify and review the accounting and controls impacts related to a number of current and future accounting changes. Some of these changes include: 1) the implementation of PGE's new Customer Information System; 2) new lease accounting rules issued by the Financial Accounting Standards Board (FASB); and 3) new revenue recognition accounting standards issued by the FASB.

Q. Have outside services increased in any other accounting services areas from 2016 to 2018?

A. Yes. There is also an apparent increase in the budget for tax consulting services. However, this is due to an unusually limited need for these services during 2016, resulting in lower than average costs. If looking across the period of 2013 through 2016, PGE's tax department spent an average of approximately $480,000 per year for tax consulting services. This compares to the 2018 forecast of approximately $206,000. With a very active legislative session in 2017, which includes a large number of tax proposals, PGE fully expects to spend its consulting services budget for both 2017 and 2018.

D. Insurance

Q. What types of insurance coverage does PGE maintain?

A. PGE maintains a prudent portfolio of insurance coverage, which we list and describe in PGE Exhibit 602 and confidential PGE Exhibit 603. 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 2018?

A. As shown in Table 4 below, we expect total Property and Casualty premiums to be approximately $11.4 million, excluding 50% of non-primary layers of Directors and Officers (D&O) insurance. PGE expects the Property program premiums to increase slightly due to an increase in PGE's total insured value coupled with a mild annual 2.0% rate increase. The decrease in Property premiums from 2016 to 2018, shown in Table 4 below, show a decrease because there was a limited-time builder's risk policy extension in 2016. If the builder's risk policy is factored out ($0.35 million), premiums show a slight average annual increase of 2.5%. Within the Casualty program, PGE expects slight increases in premiums in its General Liability, Workers' Compensation and Cyber Liability coverages. Unforeseen severe Casualty losses would produce upward pressure on rates beyond the current forecast. Overall, we expect a mild 1% impact on premiums.

Table 4
Insurance Premiums ($ millions)

Type of Loss	2016 Actuals**	2018 Budget**	Annualized % Increase
Property	$5.93	$5.88	(0.5)%
Casualty	$4.86	$5.13	2.7%
Total*	**$10.79**	**$11.38**	**1.0%**

** May not sum due to rounding.*

*** Premium amounts do not include membership credits or non-primary layers of D&O insurance*

Q. What is PGE's forecast of expenditures for retained losses from 2016 to 2018?

A. As shown in Table 5 below, PGE's forecast of expenditures for retained losses increases by approximately 14.1% annually from 2016 to 2018. We discuss retained losses in more detail below in Section 2.

Table 5
Retained Losses ($ millions)

Type of Loss	2016 Actuals	2018 Budget	Annualized % Increase
Workers' Compensation	$1.57	$1.75	5.8%
Auto & General Liability	$1.19	$1.83	24.2%
Total*	**$2.75**	**$3.58**	**14.1%**

** May not sum due to rounding*

1. Casualty

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

A. The eight components of PGE's Casualty insurance program are as follows:

- General & Auto Liability
- Directors and Officers (D&O) Liability)
- Fiduciary Liability
- Workers' Compensation
- Nuclear Liability
- Cyber Liability
- Aviation Hull & Liability
- Surety Bonds

PGE Exhibit 602 describes each policy's purpose in more detail.

Q. Why is D&O insurance coverage important?

A. D&O liability insurance is important for the following reasons:

- It insulates customers and shareholders from having to shoulder 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;
- The limits purchased are consistent with utility industry standard practices and reduce overall risk to both customers and shareholders;

- Maintaining the appropriate limit and type of D&O insurance is necessary to attract and retain qualified and competent directors and officers; and
- It shields PGE's directors and officers against normal, but sometimes significant, risks associated with managing the business.

Q. Is PGE requesting 100% of the D&O premiums?

A. No. PGE is requesting 100% of the first layer of D&O coverage and 50% of supplemental layers. PGE made these adjustments to mitigate customer costs for insurance. Although we have made these reductions in this filing, we still believe that the inclusion of 100% of D&O insurance premiums in customer prices is appropriate.

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.

2. 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 recoveries.

Q. What is the forecasted increase in annual claim expenditures for retained losses in Workers' Compensation and Auto and General Liability?

A. As shown in Table 5 above, PGE expects annual cash expenditures for retained losses for Workers' Compensation and Auto and General Liability claims to increase by an annual average of 14.1% from 2016 to 2018. The actuarial projection of annual expenditures for Workers' Compensation and Auto and General Liability retained losses is directly correlated to PGE's actual loss experience over time. In 2017 and 2018, PGE's annual expenditures are budgeted at the expected level, based on the actuarial projections.

IV. Environmental and Licensing Services

Q. Please describe the change in environmental and licensing costs from 2016 to 2018.

A. Environmental and Licensing Services (ELS) forecasted costs, as charged to A&G, are approximately $2.2 million for 2018 compared to approximately $4.4 million in actuals for 2016.

Q. Why did ELS costs decline?

A. This decrease is primarily due to the removal of environmental remediation costs and revenues associated with the Portland Harbor Superfund Sites (Portland Harbor), the Natural Resource Damage obligation (NRD),[10] the Downtown Reach portions of the Willamette River, and the Harborton Restoration Project (Harborton) from base rates. If excluding these costs from both 2016 actuals and the 2018 forecast, ELS costs charged to A&G still decrease by approximately $0.8 million.

Q. Why has PGE removed these costs from base rates?

A. PGE has removed these costs to reflect a stipulated agreement between PGE, Staff of the Public Utility Commission of Oregon, the Citizens' Utility Board, and the Industrial Customers of Northwest Utilities, stating that PGE will defer and record all environmental costs and offsetting revenues associated with Portland Harbor, NRD, Downtown Reach, and Harborton in the Portland Harbor Environmental Remediation Balancing Account (PHERA) as described in Docket No. UE 311, PGE Exhibit 100.[11] This agreement, however, is still awaiting a decision from the Commission. If the Commission's decision is materially different from the above referenced stipulation, PGE will seek to include the 2018

[10] The amounts of NRD damages or mitigation to natural resources are measured in Discount Service Acre Years.
[11] Associated Docket Nos. UM 1789, UP 344, and UE 311 have since been consolidated into Docket No. UM 1789.

forecasted costs associated with Portland Harbor, NRD, Downtown Reach, and Harborton into our 2018 test year forecast.

V. Summary

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

A. We request that the Commission approve PGE's forecast of $172.1 million in A&G costs in the 2018 test year. This represents a $1.2 million increase from 2016 actuals due primarily to increases in employee benefits (i.e., health care and dental premiums), safety, security and emergency management, and support services.

Absent cost increases for employee benefits and IT (plus the increase associated with OPUC fees), PGE has reduced its 2018 A&G forecast with an overall annualized 4.1% cost decrease from 2016.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
601	Summary of A&G Costs and FTEs
602	Description of Insurance Coverage
603C	Summary of Insurance Policies/Premiums
604	2018 R&D Proposed Projects

A&G Summary

Category	Costs ($ millions) 2014 Actuals	2015 Actuals	2016 Actuals	2017 Budget	2018 Forecast	2016 to 2018 $ Delta	2016 to 2018 Annual %	FTEs 2014 Actuals	2015 Actuals	2016 Actuals	2017 Budget	2018 Forecast	2016 to 2018 $ Delta	2016 to 2018 Annual %
Major Functional Areas														
Facilities and General Plant Maintenance	5.5	4.8	5.5	6.6	7.0	1.5	12.7%	12.9	28.2	23.3	21.9	21.9	(1.5)	-3.2%
Accounting/Finance/Tax	9.7	9.5	9.9	10.9	11.3	1.4	7.0%	69.9	69.3	70.8	79.8	79.8	9.1	6.2%
HR/Employee Support (net of capital allocs.)	8.5	9.0	9.8	11.1	13.4	3.6	16.7%	107.8	111.1	114.0	129.5	135.4	21.4	9.0%
Insurance / I&D	8.5	12.1	11.5	12.2	12.2	0.8	3.3%	6.9	6.9	7.0	7.0	7.0	0.0	0.2%
Legal	4.6	5.2	10.0	9.5	5.4	(4.6)	-26.3%	22.6	22.0	21.6	24.9	24.9	3.3	7.5%
Regulatory Affairs	2.6	2.8	2.6	3.3	3.4	0.8	15.1%	30.0	31.2	28.9	34.0	34.0	5.1	8.4%
Corporate Governance	4.5	4.5	4.6	5.1	5.4	0.8	8.0%	16.7	17.4	18.2	18.3	18.3	0.1	0.2%
Business Support Services	2.7	2.5	2.4	2.6	2.8	0.3	6.1%	7.0	7.0	5.1	5.5	5.5	0.4	4.0%
Environmental Services	2.7	4.7	4.4	2.1	2.2	(2.1)	-28.5%	-	-	-	-	-	-	#DIV/0!
Corporate R&D	1.3	1.4	2.0	1.9	3.0	1.0	23.3%	1.7	1.2	1.0	1.0	1.0	0.0	2.4%
Contract Services/Purchasing	1.2	1.3	1.4	1.4	1.4	0.0	1.0%	14.3	17.2	16.2	14.8	14.8	(1.4)	-4.6%
Security and Business Continuity	2.0	2.2	2.2	2.6	2.9	0.7	15.5%	11.4	15.0	14.0	18.0	19.0	4.9	16.2%
Corp Communications/Public Affairs	1.9	2.0	2.2	2.4	2.4	0.2	5.4%	23.4	24.3	25.0	26.2	26.2	1.3	2.5%
Load Research	0.2	0.0	0.1	-	-	(0.1)	-100.0%	-	-	-	-	-	-	#DIV/0!
Hydro Licensing and Support	0.1	0.1	0.1	0.1	0.1	0.0	4.4%	-	-	-	-	-	-	#DIV/0!
Performance Management	1.5	1.3	1.3	2.0	2.1	0.8	27.7%	15.2	10.9	12.0	13.3	13.3	1.3	5.1%
Governmental Affairs	1.0	1.2	1.2	1.2	1.2	0.0	0.8%	8.5	8.8	10.1	11.0	11.0	0.8	4.0%
Subtotal	58.5	64.4	71.0	75.0	76.3	5.2	3.6%	348.1	370.5	367.3	405.2	412.1	44.9	5.9%
Other A&G Costs														
IT: Direct & Allocated	10.2	11.3	12.1	11.0	13.4	1.3	5.3%	234.8	234.8	272.4	309.3	324.2	51.8	9.1%
Corporate Cost Reductions	-	-	-	(3.6)	(3.6)	(3.6)	N/A				(34.7)	(33.7)	(33.7)	#DIV/0!
Other Membership Costs	2.4	2.9	3.1	3.3	3.6	0.5	7.4%							
Incentives	21.2	20.9	21.6	28.2	12.6	(9.0)	-23.6%							
Severance	0.0	(0.1)	1.6	1.3	1.3	(0.3)	-9.3%							
Regulatory Fees	5.9	6.4	6.7	6.9	8.7	2.0	13.9%							
General Plant Maint.	2.3	2.6	2.6	2.6	2.9	0.3	5.3%							
Total PTO to A&G	5.3	5.9	4.4	5.9	6.3	2.0	20.6%							
Total Labor Loadings to A&G	-	(0.0)	0.0	(0.0)	0.0	-	0.0%							
Benefits (net of capital allocs.)	53.0	54.3	51.8	58.1	57.7	5.9	5.5%							
Corp Allocations	(4.5)	(3.8)	(5.7)	(7.5)	(8.7)	(3.0)	23.2%							
Revolver Fees, Margin Net Int., & Broker fees	2.5	3.0	1.9	1.9	1.8	(0.1)	-3.2%							
Subtotal	98.4	103.2	99.9	108.0	95.8	(4.1)	-2.1%							
TOTAL A&G	156.9	167.6	170.9	183.0	172.1	1.2	0.3%	582.9	605.3	639.7	679.8	702.7	63.0	4.8%

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 $1 billion 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 $1.8 billion and carry a $0.15 million deductible
Director's and Officer's Insurance	Directors and Officers ("D&O") Liability Insurance shields PGE's directors and officers against the normal risks associated with managing the business. The insurance premiums requested in this case are reasonable expenses that are necessary to attract and maintain qualified and competent directors and officers and they provide a direct benefit to PGE's customers. Currently PGE purchases $140 million in D&O insurance limits with $.75 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 $160 million with a $2 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	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.
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 $10 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.
Workers' Compensation	The State of Oregon requires PGE to maintain excess 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.
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 603C

Confidential

PGE 2018 R&D Proposed Projects
Brief Descriptions

The below R&D projects will be brought before PGE's Research and Development Committee for consideration and prioritization in 2017. PGE expects most of these projects will be continued through 2018. Due to the fluid nature of research projects, funding ratios are subject to change.

These projects primarily relate to the below topics of application:

SG	Smart Grid
SR	System Reliability
RP	Renewable Power
OE	Operational Efficiency
ES	Energy Storage
SY	System Resiliency

PGE R&D Projects for 2018		
Brief Description	**Topic**	**2018 $**
1. Joule Bank System (JBS) This is a continuation of a project started October 1, 2014 on the design and early prototyping of the Joule Bank System which involves a flexible, highly efficient, residential heating and cooling system based on heat pumps and thermal storage. Extensive collaboration has evolved to ensure arms-length, third-party assessment. Collaborating institutions include Harvey Mudd School of Engineering for thermodynamic assessment and modelling and Portland State University for initial prototype design and development. Because of the thermal storage and utility control features, it is estimated that 90% of peak demand can be eliminated and the energy storage can be "filled" mostly at PGE's discretion. In 2015, PGE concluded theoretical and prototype development; in 2016 – a bench scale "production" model was tested under real-world conditions. In 2017/2018 PGE will work with a manufacturer to evolve a field prototype.	SG	40,000
2. PSU – Battery Backup Filed Demo; Residential and Grid As electric utilities experience increasing penetration of distributed renewable power generation (wind and solar) resources at the distribution feeder level, there is heightened awareness for the need to ensure acceptable power quality from both safety and reliability perspectives. Energy storage devices will be needed to store energy when it is abundant and to release it when needed.. Development of the energy storage devices will enable the grid to respond with demand side controls and limit peak power demand. If available in sufficient capacity, energy storage devices will help resolve the present "non-dispatchability" of wind and solar power assets which currently dominate the renewable power generation resource stack mix. This development will advance the incorporation of more of these types of renewable power in response to carbon emission reduction policies through the promotion of renewable energy standards (RPS).[1] To accomplish this on a more distributed basis requires that PGE take steps similar those described above for incorporation of renewable power sources such as wind and solar. This can also be done using energy storage alone on a distributed basis. PGE has collaborated with Portland State University's Electrical and Computer Engineering (ECE) Department to take steps in the placement of battery energy storage devices at residential locations. This collaboration will allow the testing and use of a very safe aqueous ion battery that has more energy density than power density, and more suitable for household use. The vision is that PGE would own and maintain the 7 to 8 KW inverter and the nominal 50 kWhr battery as investment assets so that: • PGE through, an agreement with the premise owner, can use the battery • Controls for the battery would enable demand response, wind firming, etc. • Upon loss of utility power a disconnect allows the battery to power the home • Upon re-gaining utility power the inverter will allow automatic grid re-synching • The inverter will also monitor and control for islanding conditions • The meter for the system will track energy for home and grid separately • The meter also supports circuitry to facilitate telemetry, command and control PGE expects the battery will serve PGE's purposes for the vast majority of the time. For the home owner, the battery-inverter will provide the peace of mind of having back up power for that short period of time that loss of power is experienced on PGE's grid. The home owner knows that the battery will be supporting the increased penetration of renewable power such as	ES	40,000

[1] Oregon is one of 29 states with a renewable portfolio standard requirement. In Oregon this translates to major investor owned utilities and larger consumer or municipal owned electric utilities needing to account for 20% of power sales via renewable power resources by 2020; 27% by 2025 and 50% by 2040. This is above a baseline of the present renewable hydropower resources for these utilities meaning that these are entirely new and thus incremental to that baseline.

PGE R&D Projects for 2018		
Brief Description	**Topic**	**2018 $**
wind and solar.		
3. <u>OSU - Cascadia Lifelines Research</u> The Cascadia Lifelines Program will provide essential and unique engineering solutions including cost-effective retrofit strategies for infrastructure subjected to long-duration shaking resulting from a Cascadia Subduction Zone event. The project will provide improved prediction of ground-shaking specific to Oregon conditions, predicted seismic behavior of soils unique to the Willamette Valley, including the liquefaction potential, and system optimization of interdependent lifelines. The impact of this research will help assess cost-effective approaches to increased resilience, resulting in saved lives and improved business continuity for western Oregon and PGE's service territory. In joining this program effort headed by Oregon State University ("OSU"), PGE continues taking a pro-active approach in minimizing the impact of the next devastating earthquake on its customers, and doing its part in improving Oregon's ability to bounce back from such an event. As a secondary benefit, teaming with OSU on this research gives PGE ready access to the team of seismic hazard mitigation experts at the university. R&D funding is $50,000 per year for a 5-year commitment or $250,000 over five years; PGE occupies a seat on the management board that guides the OSU research priorities. The dollar commitment on behalf of PGE customers is substantially matched from other utility and related infrastructure providers (e.g., BPA, ODOT, NW Natural, EWEB, Port of Portland and others) yielding a match of five to 10 fold.	SR	50,000
4. <u>CEA-2045 EPRI demo of "Smart" Water Heaters & EVSE (PEV 240V Chargers)</u> EPRI has convened a group of utilities, e.g. Duke, Southern Company, AEP, BPA, TVA, appliance manufacturers; for PGE: water heaters and electric vehicle supply equipment (EVSEs) and communication device makers to conduct field demonstrations targeting 10 units of each type of appliance; mostly at PGE employee homes. The goal is to advance end-to-end capability of demand response (DR) using the CEA-2045 communication interface (also known as the appliance socket.) This is a three phase effort beginning with project planning in 2013. Projected field deployment and demonstration starts between mid-2014 to early-2015. Non-EPRI program follow up and evaluation in 2016. With this proposal PGE intends to test demand response (DR) with hot water heaters and EVSEs as demand response tools into 2017 and 2018. Expected benefits to PGE include: (1) Influence the demand responsive behavior of appliances (by providing requirements to manufacturers thru EPRI); (2) Advance efforts that PGE proposed it would pursue as part of PGE's Integrated Resource Plan (IRP) and in PGE Smart Grid reports to OPUC and finally, (3) Advance or otherwise support PGE's Retail Market Strategy to provide innovative solutions for PGE customers.	SG	40,000
5. <u>Transmission and Distribution Analytics Pilot</u> Over a period of 3 years, initially proposed for 2014 - 2017, PGE's Transmission and Distribution (T&D) Asset Management group has initiated research into a detailed analytics effort involving meter and other T&D data. This has been a long planned effort with initial scoping in 2014 that has involved looking for adequate software and vendors to provide the "big data" analytics capability and long-term support. Asset Management is close to concluding best options and thus desires to proceed. This initial pilot will drive PGE's grid optimization efforts in support of a smarter grid (integrated grid) and will be very economic based on initial cost assessments. It is also consistent with PGE's Smart Grid Roadmap. If all goes as planned, 2018 will be the year where PGE will commit capital funding bringing this effort out of the R&D stage to full implementation.	SR	0
6. <u>Dispatchable Standby Generation (DSG) Non-Emergency Emissions Conversion</u> PGE's DSG Department will continue to continue to develop a testing and monitoring protocol that will meet newly enacted US EPA requirements in a cost effective manner. This would require PGE to equip an existing DSG site that has multiple generators with real time monitoring and information logging using a unique method of gathering values from pressure	SR	0

PGE R&D Projects for 2018		
Brief Description	**Topic**	**2018 $**
transducers, thermocouples, and data logging equipment to interface to existing DSG communications infrastructure. This research will validate the new exhaust monitoring equipment and interface to an onsite data logger integrated in existing PQ meters. If successful, DSG can roll out the technology to other DSG sites and enhance the usefulness of DSG beyond 50 hours/year. If successful, the allowed use of DSG generators will change from a limited number of hours/year (by EPA) to an unlimited number of hours. This will allow PGE to utilize the DSG generators for a variety of reasons that are not allowed now, such as peak power, demand response, economic dispatch, etc. The increased potential of the DSG generators is very valuable to PGE. If the creation of 'non-emergency' DSG machines is feasible, we will move forward with converting more machines, and increase the value of the DSG program.		
7. <u>Exportable Power Demonstration using EVs</u> PGE will monitor the deployment of fleet electric vehicles (EV) capable of exporting power to the grid (e.g. Via pickup truck or equivalent) to determine effectiveness, total cost of ownership, and exportable power capabilities. This would be done in the context routine (e.g., battery support when replacing a residential transformer) and resiliency applications (e.g., powering communications hubs). The project will also assess user sentiment when compared to using existing internal combustion engine vehicles in PGE's fleet for the same purposes. This project will also explore a vehicle to grid (V2G) demonstration involving Nissan Leaf EVs and the Princeton Energy Systems bidirectional charger/inverter. This project will allow the purchase and installation of two bidirectional charger/inverters for two used Nissan Leafs and allows control of the flow of electricity to and from the vehicle to the grid. Nissan North America has the ability to modify the 2013 and newer Nissan Leaf model SL or SV to perform Vehicle to Grid Functions and is interested in working with PGE to conduct a trial in PGE service area. Nissan will provide project support and vehicle modification at no charge. Princeton Energy Systems (PES) has created a V2G Inverter/Charger that connects to a modified Nissan Leaf that can allow bi-directional flow of electricity to and from the Nissan Leaf. Control of the power flow is through an interface with the PES device and can allow increasing/decreasing the charge rate or increasing/decreasing the export of power to the grid. This device is close to being approved for use in the US. PGE would like to effect this demonstration in a fairly high visibility location to ensure public access and educational opportunities.	ES	0
8. <u>PGE Employee EV Charging Behavior Research</u> With the increased penetration of electric vehicles (EV) and supporting infrastructure -- PGE needs to research various concerns as this use ramps up – for example: • charging and driving habits of EV customers • battery life & degradation as it relates to a driver's charging & driving habits • impact of TOU rate schedule on EV charging • commuting habits of EV drivers PGE has pursued this research via studying the driving habits and usage of PGE employees as part of this R&D project.	SG	0
9. <u>**EPRI** Program 62 – Occupational Health and Safety</u> The Electric Power Research Institute's (EPRI) Program 62 (P62) provides members with research relevant to current and anticipated occupational health and safety (OH&S) issues. The deliverables derived from PGE's engagement will be used to build, update, and sustain our occupational health and safety program. P62 also provides the ability to guide future Oregon Health& Science University ("OHSU") research for the industry while leveraging the experience, ideas, and funding of other electric utility companies. Deliverables relate directly to the influence of worker protective clothing (heat/cold stress); economic evaluation of ergonomic interventions; economic safety metrics/indicators; development of an exposure database; and SF6 decomposition by-products. Additional deliverables include monthly safety webcasts (recorded), a technical workshop, and access to EPRI's technical staff. By utilizing EPRI PGE has an information resource that will allow for better short- and long-term safety	OE	50,000

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planning and strategizing. The program is designed to address both current issues and anticipate those of tomorrow.		
10. **EPR**I Program 180 – Distribution Systems Distribution system owners need to continually improve the efficiency and reliability of the distribution system, to accommodate a higher penetration of distributed energy resources (DER), and to maximize utilization of existing distribution assets without compromising safety and established operating constraints. Significant changes to distribution design and operating practices are needed to accommodate these new requirements. At the same time, utilities will continue to grapple with the ongoing challenges of an aging infrastructure, increasing customer expectations, increasing competition for resources, and an aging workforce. Recent experience with major storm events has also revealed a need to re-examine practices for designing, maintaining, and operating the distribution system to improve its overall resiliency. EPRI's Distribution Systems Program has been structured to provide members with research and application knowledge to support planning and management of the grid today and the transition to a modern integrated grid. The Program delivers a portfolio of tools and technologies to increase overall distribution reliability and resiliency; understand the expected performance for specific components throughout its life cycle; assess methods for evaluating the condition of system components; and develop and test new technologies. The program delivers a blend of short-term tools such reference guides and industry practices as well as longer-term research such as component-aging characteristics and the development of new inspection technologies. Overall, the Program includes research that supports grid modernization and provides tools for planning, design, construction, maintenance, operation, and analysis of the distribution system.	OE	170,000
11. Inspection and Correction – Below Grade Corrosion PGE is very interested in developing an inspection and correction program that facilitates learning more about below grade corrosion for its galvanized lattice towers, galvanized tubular steel poles and weathering steel tubular steel poles. The research should also include a survey of industry best practices. Presently, the Company has very little experience with evaluating the below grade condition of its steel structures. PGE will employ the services of a competent vendor or OSU, to research different techniques to evaluate below grade corrosion as well as devise and kick off a pilot program to begin looking at a sampling of its transmission towers. Early discussions between PGE and OSU note that existing corrosion rate monitoring techniques were mainly developed for measuring corrosion rate of metals with accessible measurement surfaces. For metals embedded in soils, the locations and sizes of the corroding surfaces are unknown because embedded steel surface in soil is inaccessible for direct measurements due to the presence of the thick soil cover which is electrically resistive. This limitation yields existing corrosion rate measurement techniques inaccurate, unreliable, and in most cases, unusable in field applications. The main hypothesis of the proposed research is that half-cell potentials on the soil surface can be used to identify the locations and sizes of anodic (positively charged) and cathodic (negatively charged) sites on the embedded metallic surfaces. The idea is similar to the concept of half-cell potential mapping for reinforcement corrosion in concrete, but with considerably different challenges. The soil cover has significant differences from concrete cover in chemical composition, thickness, porosity and microstructure. In addition, corrosion patterns of metals in soils are not the same as the patterns in concrete. Therefore, feasibility and applicability of half-cell potential mapping process need to be investigated. The proposed research is a multi-year effort with the following objectives: Year 1: Experimental investigation of the feasibility of half-cell potential mapping technique to identify corrosion of metals embedded in soils and identification of critical parameters affecting measurement accuracy. Year 2: Development of testing protocols to use half-cell potential mapping technique as part of regular field inspections by PGE.	SR	0

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Research will include assessing how well the technique works as well as correction methods including: below grade coatings, ground sleeves, grounding techniques, and cathodic protection. PGE has been in discussions with Oregon State University School of Engineering to craft a potential research agenda and attendant scope of work. It is likely that BPA will also find this research valuable and may also contribute funds to expand the work (e.g., different soil types, tower designs, etc.)		
12. <u>Battery Backup Demonstration with a Public or MUSH Facility</u> This project builds on a PGE field demonstration using a battery implemented in June 2016 at a PGE employee's residence. This project would create a customer or utility centric design that can be repeated at scale. This project is similar to the project crafted in Oct 2015 as part of PGE's submittal to the ODOE RFP for energy storage demonstration. The objective would be very similar to that project inasmuch as it involves a "battery-vault-on-the-feeder" design. Such a scalable design would have application at many public institutions facilities such as found at municipalities, universities, schools and hospitals (hence the term: "MUSH"). At scale, the design concept could also be supportive of non-wires solutions to regional transmission congestion.	ES	100,000
13. <u>EV Behavior for Battery State of Charge (SOC) Research Non-PGE Customer Employees</u> With the increased penetration of electric vehicles (EV) and supporting infrastructure -- PGE needs to research various concerns as this use ramps up; in particular attempt to understand; • charging and driving habits of EV customers • battery life & degradation as it relates to a driver's charging & driving habits • impact of TOU rate schedule on EV charging • commuting habits of EV drivers PGE has pursued this research via studying the driving habits and usage of PGE employees. This project utilizes a transponder device that delivers useful data sufficient to assess the above – this time using PGE employees who do not live in PGE's service territory.	SG	30,000
14. <u>NuScale Modular Reactor Study Group</u> PGE has the opportunity to assess the development and potential commercialization of the NuScale small modular reactor technology. PGE staff will do this by being part of a regional study and advisory group that has been assembled to periodically review developments regarding technical and licensing advances. This early look will help PGE assess whether, how and if this technology can advance to the point of being a cost-effective power generation solution for PGE customers and evaluation through its Integrated Resource Plan.	SR	5,000
15. <u>Biomass Supply Chain Development in Support of Boardman Conversion</u> Since 2009, PGE has investigated the potential to use torrefied biogenic biomass to displace coal at its Boardman Power Plant. This has been coupled to the need to pre-process the biomass through torrefaction in order to make the fuel sufficiently friable (crispy) so that it can be ground to a fine powder in the Boardman pulverizers. PGE has done early exploration in partnership with OSU Extension into a biomass supply chain via energy grass agronomy especially for Arundo and Sorghum. In 2016, PGE worked with Oregon Torrefaction, LLC to explore the availability of woody biomass derived in part, from USFS Forest Stewardship contracts out the Malheur National Forest. As Boardman gets closer to its commitment to cease use of coal at the end of 2020; PGE will need to firm its views of what will be the potential biomass supply chain components sufficient to fire the Plant at 30% to 40% capacity.	RP	110,000
16. <u>OSU Wave Energy Support</u> PGE continues its support of OSU to develop and test intermediate/full scale wave energy generation devices in the Wallace Energy Systems and Renewables Facility (WESRF) Lab (linear test bed), Hinsdale wave flume, and/or Northwest National Marine Renewable Energy	RP	30,000

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Center (NNMREC) open ocean test berth – Pacific Marine Energy Center (PMEC). This will demonstrate and expand the available renewable resources for PGE customers. In 2017/2018 PGE will continue its support of OSU research into specific component including mooring design, energy extraction and other critical equipment.		
17. PSU-PGE Smart House Design; Streetlights; Smart City Research PGE in collaboration with PSU will, through an interdisciplinary competition or incentive, attempt to create broad-perspective solutions for grid/renewable friendly “smart” homes. Focus will be on solutions for homes that have the ability to use and/or store renewable energy when over generation occurs as wind and solar generation approaches 50% in California and later in WECC. This is more commonly referred to as the “duck curve” when solar over generation will be evident especially in California due to its very aggressive renewable portfolio standard.	SG	10,000
18. U of O, Regional Solar Radiation Data Center Project This project supports the University of Oregon’s (“U of O”) longstanding collection and storage of regional solar energy data and the maintenance of calibration equipment. This data is supplied to the U. S. Department of Energy’s National Renewable Energy Laboratory (NREL) and made available to all utilities for siting of utility scale solar projects. The calibrated solar instrumentation can also be used to validate PGE’s present and future distributed solar photovoltaic (PV) resources performance; ancillary meteorological data will be used to estimate effects of wind on distributed PV solar resources. Supporting these local solar sensing stations provides PGE customers with more granular solar data useful for optimal siting of solar photovoltaic devices.	RP	10,000
19. Portland State University (“PSU”) – Investigate Wake Effects on Biglow Canyon Phase 3 Production This project proposes research to optimize the blade length and rotor rotation for the Siemens wind turbines at Biglow Canyon Wind Farm. This will increase the performance/output at PGE’s Biglow Canyon Wind plant and thus its overall power output with potentially only small capital outlay. The optimization research and resulting power modelling validation would utilize the wind tunnel available at PSU.	RP	20,000
20. OSU – Real-time Load Modelling OSU’s S-Phasor Network, Microgrid Reliability The goal of this project is to better understand load models in order to advance grid protection of the next generation (integrated grid) power transmission and distribution infrastructure. With assistance from the growing PMU network at OSU, a composite dynamic load model can be estimated in real time and provide useful insight into the design of microgrid protection schemes. This will address challenges such as reverse flows, automatic reclosing, or delayed relay tripping. This project will provide PGE and its customers with insights about the benefits of deploying phasor measurement units (PMUs) at the distribution level yielding improved analysis of anomalies from modern, non-traditional loads, as well as synchronization between transmission and distribution level sensing.	SG	35,000
21. OIT – Second Life Battery Research This project allows PGE in collaboration with Oregon Institute of Technology (OIT), to learn about and implement uses of second life batteries. In particular, there is a desire to better understand the comparative life cycles of Li-Ion, Zinc-Bromide, and Sodium-Sulfur batteries as it applies to grid level storage/islanding applications. The approach would be to obtain multiple types of batteries that are candidates for the second life study: (1) Perform SOC (%), (2) capacity, (3) life cycle, and efficiency, (4) charging-discharging, and reaction time analysis of candidate electro chemistries. This project will deliver a formal, evaluated report with the comparison data. These results would allow PGE to be better positioned to understand how 2nd life uses of long-lived batteries can be cost-effectively applied to other applications that will benefit its customers. These tests will be conducted at Oregon Renewable Energy Center	ES	35,000

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(OREC) under a controlled environment.		
22. OIT – Comparative Studies of Energy Storage: CAES, Batteries, Super Caps PGE and OIT propose collaborative research to simulate proposed, new energy storage systems in combination with design and testing of small scale energy generation/storage devices at the Oregon Renewable Energy Center (OREC). The simulation would generate data to determine, for various applications, the optimal storage systems for PGE. These simulations would help PGE and its customers understand: • Compressed air energy storage systems: efficiency, feasibility, capacity, and geological requirements/impact studies • Ultra-Capacitors: Graphene and Carbon Nanotubes, Charging & Discharging Characteristics • Hybrid Li-ion & Ultra Capacitor Systems: reaction time, cost • Cost of implementation, Peak load applications, long term applications	ES	35,000
23. Torrefied Biomass Fuel Test Burns for Multiple Days - Proof of Concept Since 2010, PGE has embarked formally on a large R&D effort to assess the feasibility of displacing coal at its Boardman pulverized coal plant with torrefied biomass. This project extends that effort with work to fine tune both the production and the use of the new fuel in the Plant's boiler. The project will also support evolution of new fuel handling, processing and safety procedures associated with both green and torrefied biomass. The project will also closely monitor torrefied fuel performance and emissions in both co-fire, as a transition, and 100% torrefied biomass applications. This project specifically evolves support and techniques to safely and cost-effectively apply torrefied biomass as fuel to displace coal at the Boardman Power Plant.	RP	300,000
24. **EPRI** P60 EMF and RF Health Assessment & Safety (3-year) The Electric Power Research Institute's (EPRI) Program 60 addresses electric and magnetic field (EMF) and radio-frequency (RF) exposures and health issues. Planning and building new transmission and distribution (T&D) projects takes on heightened importance as the power grid is upgraded and modernized by increased asset capacity and integration of smart grid technology and remotely-located renewable energy resources. New T&D construction and capacity upgrades to T&D lines and substations, building electric vehicle (EV) charging infrastructure, and expansion of smart grid technology's reliance on two-way wireless communication, can create public concerns about possible human health risks from EMF and RF exposures. Such concerns can lead to lengthy delays and regulatory decisions affecting project schedules and costs. Program 60 provides PGE with research, analyses, and expertise to better inform public dialogue and regulatory oversight. It is comprised of two project sets, P60A: Community and Residential Studies and P60B: Occupational Studies. These deliver timely, reliable EMF and RF research results, including communication materials, relevant background information, and analyses of key external studies. Program 60 research, combined with EPRI staff expertise, contributes to EMF and RF scientific knowledge, better enabling objective health risk evaluations and exposure guideline development aimed at reducing uncertainties for PGE customers and PGE workers	SR	146,000
25. **EPRI** P64 Boiler and Turbine Steam & Cycle Chemistry Safety and availability loss due to failures are two key issues driving R&D on major fossil power plant components, especially in older plants. Operators need to minimize major causes of lost availability and associated maintenance costs related to corrosion and inadequate cycle chemistry, and prevent boiler tube and turbine blade/disc failures and flow-accelerated corrosion (FAC). Generation assets are experiencing increasing demands for greater operating flexibility, low-load operation, and more frequent unit shutdowns and cycling. These demands are raising	SR	30,000

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additional key issues, including the dynamic impacts on plant systems and the preservation of equipment. Operators need to minimize and mitigate the increased risk of corrosion damage and component failures presented by these special operating regimes. EPRI's Boiler and Turbine Steam and Cycle Chemistry Program offers guidelines, technology, and training materials to help plant operators manage water/steam cycle chemistry, reduce unplanned outages and operations and maintenance (O&M) costs, and improve unit efficiency, as well as address chemistry requirements of flexible operation and proper equipment storage. The industry needs to balance risks & costs of the most costly equipment by using proven technologies to create solutions. By using the results of the R&D in this program, members can: • Improve overall unit availability and flexibility: Losses due to improper chemistry have a 1% or more effect on unit availability • Reduce steam turbine efficiency losses: Chemical and metallic oxide deposits reduce turbine efficiencies by up to 2%		
26. **EPRI** P68 Instrumentation, Controls and Automation Instrumentation and control (I&C) systems affect all areas of plant operation. Every component, process, system, and person relies on instrumentation and controls to identify, communicate, and control process data to ensure the safe, reliable, efficient and cost-effective operation of the plant. As older plants continue to age and new plants are built, instrumentation and control systems become increasingly more vital in helping a power generator meet its strategic mission of capacity, efficiency, and reliability. EPRI's Instrumentation Controls, and Automation program identifies, develops, and demonstrates state-of-the-art sensing, monitoring, diagnostics, and control system technologies that improve equipment condition assessment and plant performance, and help accurately measure critical plant parameters. This program focuses on providing integrated instrumentation and control solutions that enhance processes, technologies, and operations and maintenance, which can enable program members to: • Reduce costs through greater automation in tuning of process controls and operating point transitions. • Improve reliability through integrated anomaly detection, diagnostics, and prognostics. • Improve reliability through more effective equipment monitoring, made possible through collaborative R&D.	SR	47,000
27. **EPRI** P69 Maintenance Management & Technology The Electric Power Research Institute's (EPRI's) Maintenance Management & Technology program helps power generation plant owners and operators address common industry challenges related to maintenance program structure and functionality. EPRI works with top-performing organizations to collaboratively research and develop maintenance processes and technologies that help improve the safety, reliability, and performance of plant equipment and organizations. Research projects include efforts to identify potential causes of equipment failures, effectively monitor and assess the condition of equipment, and proactively plan for equipment maintenance. A significant part of these research efforts involves the management and communication of data and information necessary for monitoring and maintaining power plant assets. This program helps its members transition to, and sustain, the most efficient and effective practices associated with plant maintenance. The key attributes of an optimized program are adoption of information management needed to support a condition-based approach to maintenance, and replacement of costly corrective maintenance with proactive preventive maintenance. Using the results of this program, members can: • Achieve operation and maintenance excellence through an integrated approach that includes process improvements, related technologies, and knowledge management • Address current issues associated with the need for flexible plant operations, asset retirement, and new reliability standards	SR	72,000

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• Better standardize O&M programs, processes, and procedures • Increase plant availability and reliability through improved maintenance management and staff performance		
28. **EPRI** P94 Energy Storage and Distributed Generation Energy storage and distributed generation technologies are attracting increasing interest from utilities and regulators as localized flexible grid assets. Storage can act as a buffer between electricity supply and demand, increasing the flexibility of the grid and allowing greater accommodation of variable renewable resources. Distributed generation (DG) entails the production of power at or near load centers, thereby augmenting or substituting electricity infrastructure with DG fuel infrastructure, where appropriate. Both storage and DG may provide temporary solutions for regional and local capacity shortages, and may provide relief to localized transmission and distribution congestion. Technology advances, as well as investment in production capacity, have resulted in significant cost reductions of energy storage and distributed generation. However, the economic use of these technologies still generally requires the user to take full advantage of multiple potential benefit streams ("stacked benefits"). The various applications that contribute to the value of distributed resources have different requirements, and the ways in which these requirements are coincident or competitive are still being explored. Technologies such as fuel cells, micro turbines and small reciprocating generators are still relatively expensive in terms of installed capital cost, but low fuel costs and opportunities offered by the application of combined-heat-and-power (CHP) architectures may make them increasingly cost-effective options in the future. It is important to understand the factors that may make storage and distributed generation technologies technically and economically viable in the future, whether the devices are owned and operated by utilities, by customers, or by third-parties. While storage and distributed generation options are rapidly maturing and are beginning to become practical in grid applications, there are still significant challenges to overcome.	SG	100,000
29. **EPRI** P104 Generation Maintenance Applications Center Power generators globally face chronic equipment problems in the more than 1,500 non-nuclear generating units that are up to 30 years old or older. Power generating companies are constantly seeking to reduce maintenance-related O&M costs for aging equipment while improving unit reliability through incremental component improvements, but are challenged by diminishing collective experience and knowledge and an urgent need to develop new maintenance and engineering staffs as the current workforce retires. The training and knowledge that are needed to educate and inform new staffs are not always readily available from vendors or equipment suppliers in a comprehensive format ready for use. New maintenance challenges are created by the addition of equipment to upgrade the performance and improve the emissions of these existing plants. In addition, new generation in the form of combined-cycle combustion turbines, bio-fuel boilers, and wind farms is adding to the need for innovative development guidance for the new types of balance-of-plant (BOP) components in these units that was not previously included in GenMAC's portfolio. EPRI's Generation Maintenance Applications Center GenMAC program provides practical information for improving plant maintenance-related operations and maintenance processes, reliability, and cost through collaboration with participating organizations. Materials can be used to transfer base knowledge to workers new to the organization and by experienced staff searching for reliability enhancements for maintenance tasks.	SR	40,000
30. **EPRI** P194 Heat Rate Improvement Program PGE always attempts to contain operating costs and this increases the need to improve plant heat rates. Heat rate improvements bear a direct relationship to tonnage releases of all air emissions, including CO_2. The integration of heat rate assessment capability into retrofits of operating	OE	0

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plants and new plant designs is critical to ensuring the optimal efficiency in plant operations. The focus of the Electric Power Research Institute's (EPRI's) Heat Rate Improvement program (Program 194) is to improve operating plant heat rate, independent of the fuel fired. The program will advance the state of the art, benefitting all power generating companies -- including those now starting performance improvement programs and those with vast experience and mature programs. The efforts behind improving heat rate require a broad understanding of power plant design, operation, maintenance, ambient conditions, thermal sciences, combustion, and the type of fuel fired. To be successful, many factors must be taken into account to ensure results are both cost-effective and do not create problems elsewhere in the plant. The Heat Rate Improvement program activities include research on thermodynamics, auxiliary power consumption, heat transfer, plant processes, controls, new hardware, fluid dynamics, measurement, and software, in addition to issues related to fuel quality and the combustion process. The Heat Rate Improvement program focuses on an approach that cost-effectively enhances power plant efficiency without creating side effects. Potential heat rate improvements include: • Significant savings in fuel costs and are by far the lowest-cost and a proven and commercially available method for reducing CO_2 emissions. • Overall combined-cycle plant performance, permitting those sites to reduce fuel costs per MW as their capacity factors increase. • Cost savings through improved boiler performance, regained capacity, and increased flexibility in fuel sourcing. • Revealing reliability related problems in the quest to identify performance or thermal efficiency problems, permitting timely maintenance and a reduction of generation costs. • Enhanced operational flexibility by improving plant performance at part and low load.		
31. **EPRI** P170 End-Use Energy Efficiency and Demand Response The electricity industry must meet customers' continuous demand for power as well as provide safe, reliable, affordable, and environmentally responsible service to customers. Utilities and policy makers in the United States and abroad are increasingly turning to energy efficiency as a resource to help address these challenges. Many U.S. states have enacted legislation that mandates specific energy-efficiency savings goals, and some explicitly require utilities to place energy efficiency as the first opportunity in their resource planning initiatives. Key to the realization of these goals is the development and adoption of emerging energy-efficient technologies and best practices. It is also important for utilities to characterize the grid impacts of customer interaction with emerging energy technologies, and to develop platforms for their integration as resources to enable an Integrated Power System. Interaction with the 'connected' customer that will provide both energy efficiency and demand response benefits to those customers that are crucial for the "utility of the future". This program is focused on the assessment, testing, demonstration, deployment, and technology transfer of energy-efficient and demand-responsive end-use technologies to accelerate their adoption into utility programs, influence the progress of codes and standards, and ultimately lead to market transformation. The program also develops analytical frameworks essential to utility application of energy efficiency and demand response (DR) in order to enable the Integrated Power System, with particular focus on end-use load research and data analytics.	SG	5,000
32. **EPRI** P173 Bulk Power System Integration of Variable Generation There has been a significant increase in the implementation of renewable energy, due to state mandated policy decisions on renewable energy standards and federal air and water standards, along with improved economic viability for these resources. Much of the estimated development of renewables comprises variable resources as wind generation and solar photovoltaics (PV), which when integrated with the grid, create new challenges for maintaining reliable system operation. Future projections are that a more significant build-out of these variable renewable resources is likely at both the transmission and distribution levels. Power system planners and	SG	75,000

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operators will require new tools and resources to ensure a reliable, sustainable, and cost-effective supply of electricity to consumers. New tools needed include improved and/or new sources of system flexibility to respond to and accommodate the increase in energy variability and uncertainty, the development of additional transmission infrastructure to deliver energy from remote locations, and planning and operational methods and software to effectively plan and operate the bulk system with these new resources, many of which may be at the distribution level. This research program addresses these needs and directly supports EPRI's Research Imperatives #2 "Integration of Dynamic Customer Resources and Behavior" and #3 "Integrated Power System and Environmental Modeling Framework." Research is focused on -(1) The Bulk Power System Variable Generation Integration research program which provides variable generation integration analytics; (2) development of planning and protection methods, tools, and models; and (3) development of operator methods and tools to reliably and economically integrate wind and solar PV generation.		
33. **EPRI** P174 Integration of Distributed Energy Resources Increased amounts of distributed energy resources (DER) in the electric grid bring a number of challenges for the electric industry. Utilities face large numbers of interconnection requests; distributed generation on some circuits will exceed the load; and many operating challenges involving feeder voltage regulation, hosting capacity limits, inverter grid support and grounding options are involved. Furthermore, providing reliable service as DER penetrations increase and electricity sales diminish can also add economic and business challenges to the technical ones. This Program addresses these challenges with project sets that assess feeder impacts, inverter interface electronics, and integration analytics. The Program evaluates case study experiences and strategies related to future business impacts. It also evaluates leading industry practices for effective interconnection and integration with distribution operations. Many of these activities support EPRI's "The Integrated Grid" initiative. This Program includes lab and field evaluations and demonstrations of improved DER power management and communications. A primary objective of the work in the field is to expand utility hands-on knowledge for managing distributed energy resources—without reducing distribution safety, reliability, or asset utilization effectiveness. Moreover, the optimal integration of distributed energy resources, like solar photovoltaic (PV) generation, has the potential for significant public benefits. These include reduced climate impact of overall electric power generation, potential for more efficient and optimum operation of the electric system through efficient generation closer to the load and even improved resiliency with local generation to provide power during major events on the grid. Achievement requires making these distributed resources a part of the planning and operation process inherent to an Integrated Grid.	SG	40,000
34. **EPRI** P183 Cyber Security This program develops an analysis framework to correlate cyber, physical, and power system events including: • Development of security event scenarios that utilities can adapt to their operational environment • Identification of operational and asset condition data sources to support event detection; and • Results and lessons learned from testing and demonstrating scenario detection in EPRI's lab as well as utility host sites. Utility enterprises are evaluating cyber security threats to their communication networks in a way that integrates that information with other traditional information about equipment health status and power system status. It is now time to integrate this information into a comprehensive and consistent picture, for use by power system operators and communication system operators, in order to provide a system-wide view and to improve coordination of operator responses. This project intends to focus the "Analysis" component of the Integrated Threat Analysis Framework (ITAF) by developing and testing broadly applied use cases and potential data analysis methods to determine when a malicious event has taken place. While the aggregation of data from these	SR	95,000

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domains (Information Technology, Operations Technology, Physical, threat indictors, etc.) provides a view across the entire utility enterprise, determining how to use this information to make decisions will be very challenging. The operational environment will vary day-to-day due to changing conditions (weather, loading conditions, availability of variable resources, planned or unplanned maintenance, etc.) so the use cases must be dynamic and represent a growing knowledge base as opposed to a set of static scenarios. This challenge will require expertise in both cyber security and grid operations. This project coordinates activities of three EPRI research programs: Substations (P37), Grid Operations (P39), and Cyber Security (P183) in a way that is intended to provide broad power industry and public benefits, including better communication between diverse utility personnel and public service personnel.		
35. **EPRI** P199 Electrification for Customer Productivity PGE's industrial and commercial customers are constantly striving to increase productivity and enhance their competitiveness in the global marketplace. In many cases, electrification – i.e., the application of novel, energy-efficient electric technologies as alternatives to fossil-fueled or non-energized processes – can boost utility productivity and enhance the quality of service to these customers. Electricity offers inherent advantages of controllability, precision, versatility, efficiency, and environmental benefits compared to fossil-fueled alternatives in many applications. A lack of familiarity and experience with emerging technologies, however, impedes many customers, particularly small- to medium-sized businesses and civil institutions, from pursuing electrification measures that can improve the productivity and efficiency of operations. Such enterprises would benefit from information and support from PGE. However, electric utilities themselves face obstacles to serving as effective utility partners in this regard. Identifying and measuring the prime opportunities for electrification in a given service territory can be difficult. One of these is the lack of an analytical framework for quantifying the net benefits of electrification strategies – from the customer, utility and societal perspectives. The P199 research program aims to address gaps like this by developing and refining analytical tools and an objective knowledge base of technologies, applications, and markets and facilitating stakeholder networks to help utilities evaluate and pursue electrification opportunities in partnership with their customers.	SG	0
36. **EPRI** Power Quality Knowledge Development and Transfer Deregulation has been made even more difficult for utility management of electrical power quality issues. It has grown even more difficult with deregulation, reregulation, increasingly scarce technical and strategic tools, and a conspicuous lack of unbiased resources for information, collaboration, advice, and problem solving. Moreover, with the ever-increasing use of sensitive digital and electronic equipment in today's economy, PGE's end-use customers are not only demanding higher quality power, but also are calling upon it to help resolve PQ problems within customer facilities. This EPRI supplemental project offers a number of benefits, including: access to EPRI experts and industry peers, access to high-impact resources, such as documents covering a wide range of PQ topics, and access to MyPQ.epri.com, a comprehensive electronic PQ resource providing 24/7 access to more than 500 PQ case studies, PQ technical documents, PQ standards references, indexes, conference presentations, and a wealth of other resources.	OE	30,000
37. Salem Smart Power Center (SSPC) Use Case Testing & Validation PGE has implemented the Salem Smart Power Project (SSPP) delivering five assets that were funded as part of the US DOE's 5-year, $178 million Pacific NW Smart Grid Demonstration Project. The SSPP effort expended $25 million of which 50% of the cost was covered by US DOE stimulus funding beginning in 2010. The remaining 50% was 50-50 cost shared between PGE and its principal vendors: Enerdel, Eaton and Alstom. PGE's overall cost was $6.5 million and yielded the Salem Smart Power Center (SSPC) which showcases a 5 MW, 1.25 MW-hr lithium ion battery-inverter system (BIS) and related assets – all of which have been capable of	SG	0

PGE R&D Projects for 2018		
Brief Description	**Topic**	**2018 $**
responding to a transactive control signal. The facility is located at PGE's Oxford substation in Salem Oregon and is grid-tied via the 12.4 kV Rural Feeder line. Sixteen use cases have been identified of which 9 have either been validated or discarded for potential autonomous single use. Below are the remaining cases PGE should continue to pursue. After single use validation, optimized concurrent use for multiple use cases will be attempted. • 400 kW of Demand Response Benefit (DR) • 1.3 MWh of Energy Shift from on-Peak Costs to Off-Peak Costs • 2 to 4 MW of Real-time Voltage Support for System Operations • ≈ 1.2 MWh of Off-Peak ability to Absorb Excess Wind Power • Distribution Automation Using Advanced, Intelligent Switches • Adaptive (Dynamic) Conservation Voltage Reduction • Using the SSPP as a Dispatchable Standby Generation Resource		
38. <u>Develop & Assess Model to Gauge DSG Program Target Capacity</u> PGE's dispatchable standby generation (DSG) program is unique and currently possesses 107 MW of dispatchable power largely in the form of diesel fueled gen-sets at over 60 customer sites. The DSG program has unparalleled capability to supply non-spinning reserve and has been a remarkable addition to PGE's non-central station power generation mix. This research proposes an effort to model and then understand the possible upper limit of the DSG effort and most importantly – discern the governing, if not principal limiting factors. This assessment will allow PGE to best deploy its resources to optimizing the program on behalf and for the benefit of all its customers.	SG	0
39. <u>Behind the Meter Use of Energy Storage & Solar PV – Customer Behavior</u> As noted by the US DOE, energy storage applications can be closely coupled to smaller scale applications. Commonly mentioned applications include: • Demand Response Programs for peak shifting • Integration with Electric Vehicle Infrastructure for energy storage and peak shifting • Commercial Building integration to optimize energy use; support Peak Energy Shift • Integration with Residential Use cycle(s) for peak shifting With this background, PGE proposes explore to opportunities to engage customers in buying or contracting for energy storage at their buildings, for both residential and small commercial. The behind-the-meter (BTM) storage market is still nascent, with two leading companies Sonnen and Tesla PowerWall, the former with almost 1,000 systems deployed in the US and the later starting to ship product. Utility programs offering these types of systems are also new; existing programs provide a platform where customers can buy or lease the battery/inverter system (BIS) to provide backup power to the home during an outage and used by the utility for utility services during other times. There is still a lot of work needed including to determine ownership structures, the value of the BIS to both the customer and the utility, and proving distributed energy resources can be controlled and used for utility services. PGE believes, however, that these systems are coming and that PGE, on behalf of its customers, needs to gain experience in installing and operating the systems as well as to develop a strong partnership with the vendors. Therefore this project will 1) install a Sonnen Battery system at an employee's house and 2) install a Tesla Powerwall at Portland State University. As a result, PGE on behalf of its customers, expects to: • Develop a partnership with each vendor • Learn about the procurement and installation process	SG	75,000

<table>
<tr><th colspan="3">PGE R&D Projects for 2018</th></tr>
<tr><th>Brief Description</th><th>Topic</th><th>2018 $</th></tr>
<tr><td>Collect and analyze BIS operational data:
Round trip efficiency – quantify lifespan degradation over time
Analyze outage information – how long did the battery hold up the house?
Charge/discharge rates
Noise
Response time
Demonstrate local integration of renewable generation
Demonstrate control of distributed storage for utility applications
Obtain employee feedback on implementation, operation during outages, ways to improve service and terms of service, effect on lifestyle, peace of mind, etc.
Demonstrate the reduced cost of storage for utility applications by capturing the value for customer reliability (reduced outage time)
Determine the value of local renewable integration
Validate 10% capacity credit, as compared to central generation
For the PowerWall option assess the safety of the system for residential applications</td><td></td><td></td></tr>
<tr><td>40. <u>EPRI Computer Based Training Modules for Sulfur Hexafluoride (SF6) Handling</u>
EPRI’s SF6 (Sulfur Hexafluoride) Computer-Based Training (CBT) Modules consist of five sub-modules that each provide approximately one hour of instruction to users on SF6 topics. A browser interface helps the user navigate through the interactive training. As the user moves through the module, it provides instruction and assessment. At the end of the module, the user receives a final scored assessment and a pass/fail result. Five SF6 sub-modules are included in the package: Safety, Handling, Analysis, Detection and Environmental Impact. These computer-based training modules are maintained as part of “Program 37: Substations”, The program and the CBT provide updated and efficient training covering a large amount of SF6 knowledge in a highly usable format. SF6 is used in electrical switchgear as an insulating gas and has both industrial hygiene and greenhouse gas concerns if handled inadequately. Training materials will be used primarily for transmission and distribution (T&D) personnel and as new or better practices evolve – this EPRI program will allow PGE to stay current with best practices.</td><td>OE</td><td>10,000</td></tr>
<tr><td>41. <u>EPRI P87 Fossil Materials and Repair</u>
PGE’s fossil power plants are increasingly tasked with flexible operations, pushing for maximum output during peak price periods, transitioning to low-load and multi-shift operation, and frequent fuel switching to take advantage of spot market opportunities on behalf of its customers. These practices can accelerate material damage in major power block components due to frequent cycling of operations, i.e., increased “wear and tear”. New materials are being introduced for replacement of components in aging plants, in the building of higher-efficiency power plants, and in the construction of components with thinner walls for improved operational flexibility. Regulations on air and water quality have resulted in construction of new pollution control equipment and water management technologies that are more demanding on materials than older systems.

Improved knowledge of materials behavior in this environment allows for accurate prediction of remaining life, proper choice of repair strategies, and optimized material selection, fabrication, and repair. To address these needs, PGE proposes to participate in EPRI’s Fossil Materials and Repair program (Program 87) which provides integrated materials selection guidance, repair and welding technologies, and corrosion mitigation methods to improve equipment performance, reliability, and safety on behalf of its customers. Research is conducted in all areas of the fossil power plant, including the major power block (boilers, HRSGs, steam turbines, gas turbines, etc.) and the balance of plant. Goals of this program include:
Increase availability through better understanding of plant materials.
Minimize or eliminate -- repeat failures and equipment damage, and reduce outage frequency and duration by using improved knowledge of damage mechanisms and tools</td><td>SR</td><td>50,000</td></tr>
</table>

PGE R&D Projects for 2018		
Brief Description	**Topic**	**2018 $**
for life-assessment methods. • Reduce failures from high- and low-temperature corrosion. • Obtain in-depth knowledge of advanced ferritic and austenitic alloys and processes used to fabricate and join these alloys. • Select appropriate weld filler metals and processes for construction and repair. • Reduce outage time and manage maintenance costs through implementation of innovative repair techniques. • Maximize component life through improved materials selection guidance and procurement specifications.		
42. <u>Multi-Family Energy Management (2-year project)</u> The goal of this project is to evaluate smart energy management technology for energy efficiency and demand response benefits in the multifamily sector. Study partners include: EQL Energy, Portland State University, IOTAS, Energex, and College Housing North. The Study proposes to include two vendors' suite of products, at 4 sites (3 using Iotas, 1 using Energex), and will examine energy savings that comes from controlling HVAC equipment based on sensor data, occupancy, consumer behavior, and control features. The two vendors have distinct differences in experience, target customers, platform cost and functionality. This study will be able the collection of data and evaluation of many of the energy saving variables associated with multifamily energy use, e.g., landlord and tenant behavior, environmental and energy use feedback, and effectiveness of sensor and control technology. This study will examine savings information only to Information, sensors plus enabled controls (smart). The principal deliverable will be to quantify the amount of energy and capacity savings improvement when users can employ smart sensors and control, versus the information only scenarios. This research addresses use of smart technology to increase energy efficiency of multi-family structures and to the extent it proves itself – will allow PGE to recommend to customers – technologies to lower their energy costs.	SG	60,000
43. <u>**EPRI** P88 Combined Cycle HRSG and Balance of Plant (3-year)</u> This research will use work performed by EPRI to improve the design and operation of the heat recovery steam generators (HRSGs) at PGE. This work can be utilized by plant operation and maintenance teams and the corporate engineering group for the design of new plants, and the project engineering group when it comes to new upgrades/improvement projects to ensure that the new projects take into account the latest and best practices are included in the new design. The research information included in program 88 will provide training material for PGE employees, and keep best practices available so that PGE works proactively in identifying issues and addressing them, before these issues can become a safety concern or impact plant reliability. Joining Program 88 will also allow PGE to have input on the projects that will be evaluated by EPRI and participating industries that are not electric utilities. This will benefit PGE by having EPRI work on projects that are specific to PGE. PGE can also benefit by utilizing the EPRI team as a resource when it comes to evaluating design of new projects or other evaluations related to program 88. PGE currently owns 3 HRSGs not including Beaver or Coyote 2 unit. Some of the plants are around 10 years old and it will be very important for PGE to stay at the forefront of the new research s and apply the latest technology to our HRSGs. This may be even more important as PGE prepares to enter the Energy Imbalance Market (EIM).	SR	68,000
44. <u>Utility Demonstration Projects & Pilots – Best Practices; Lessons Learned</u> PGE conducts many demonstration and pilot efforts to better serve its customers. This project will help improve our process related to the development of all pilots and technology demonstrations by understanding what we do particularly well and where we can learn from other utilities successes and failures. This collaboration will focus on distilling lessons learned from recent utilities (see below) and customer experiences. Rather than providing specific technical support for particular projects, the emphasis of this research is to identify broad best	OE	30,000

PGE R&D Projects for 2018		
Brief Description	**Topic**	**2018 $**
practices in the design, structure, and execution of pilot and demonstration projects. It provides the first attempt to benchmark PGE's pilot and R&D approach against other utilities. Past and present participants include: Rocky Mountain Institute (convener), ConEd, Avista, APS, (confirmed) and other utilities (possibly SCE, SMUD, Duke, Xcel, National Grid, PSE, and Entergy). PGE will use these learnings to revise and improve our process and approaches to pilot development and design.		
45. <u>Oregon BEST – NW Energy Experience Prize Participation</u> In 2015 and 2016, PGE has participated in the NW Energy Experience Prize (NW Energy XP) program. The effort fosters and leverages collaboration between several universities, along with subject matter experts from regional utility and power companies. The program gives students hands-on experience and knowledge that cannot be learned in the classroom. In return, utility staff gets in-depth research on selected topics / problems facing today's power and utility industry. Participating universities include PSU, OSU, OIT, UP, and WSU-Vancouver. Past topics of interest to PGE include: use of drones for high tower inspections; impact of demand response penetration; impact of distributed renewable power penetration into PGE's service territory. Topics anticipated for 2017 consideration include demand response, renewable biomass use and smart city topics. If any of these are selected it will be likely that PGE will commit funding in either 2017 or 2018 to pursue a partnership with the sponsoring universities and their research team(s) as part of this program.	SG	0
46. <u>Non-Wires Solutions to Transmission Congestion</u> PGE in collaboration with PSU proposes a competent and authoritative research paper to set context and to analyze the possibility of using recent energy storage advances to alleviate grid congestion. . The Pacific Northwest transmission grid is congested, and especially true of east-west electricity movement, including localized areas. The congestion has grown over the years due to load center growth on the west side of the Cascade Mountains and the proliferation of wind power plants on the east side of the mountains. As BPA controls 75% of the region's transmission system this is a top concern of PGE and its customers, since PGE has a heavy reliance (as do virtually all electric utilities in the region) on the BPA system. In southwest Washington and Multnomah County, Oregon where the population has more than doubled there has been no transmission line upgrade or expansion for forty years. This led the BPA in 2011 to propose the "I-5 Corridor Transmission Reinforcement Project" to construct new transmission to help relieve congestion for Cowlitz, Clark and Multnomah Counties. This is roughly a 70 mile run extending from Longview Washington to Troutdale Oregon with construction alternatives being evaluated on the Washington side of the Columbia River. The ability to construct new transmission lines is expensive, daunting and given recent experience might not be possible at any price. The advent of large grid-scale energy storage systems of which PGE's Salem Smart Power Center is an example suggests the possibility of a non-wires option to help relieve transmission congestion. Energy storage can effectively serve as a "wide spot" in the pipe and with a sufficient number of installations could eventually widen the pipe entirely and be a viable solution to the congestion issue.	AR	25,000
47. <u>Resiliency Applications of EVs in Post Seismic Events or Equivalent (V2G)</u> The use of electric vehicles (EV) to support recovery efforts after a natural disaster is of growing interest to emergency planners. From their perspective, electric vehicles are more than just cars - they are also mobile batteries that can provide back-up power to homes, pop-up clinics, and shelters, and offer a more reliable source of transportation than gasoline-dependent vehicles. Perhaps the most notable example to date of electric vehicles being used in emergency response occurred within just two years of the first models coming onto the market in 2010. After a massive tsunami and earthquake hit Japan in 2011, the Nissan LEAF, Mitsubishi i-MiEV, and other electric cars <u>were used as generators and a reliable mode of transportation</u>, demonstrating the technology's advantages. This project will explore this emerging topic – to include looking at the benefits as well as the challenges of using electric vehicles to support recovery efforts after a	SY	25,000

PGE R&D Projects for 2018		
Brief Description	**Topic**	**2018 $**
hurricane, earthquake, or other disasters. The research will also review strategies for incorporating electric vehicles into an emergency response plan. The research will address the central question -- if electric vehicles are considered an asset, how can planners and government leaders prepare their organizations and their communities to fully take advantage of them?		
48. Exploring Bidding the SSPC Battery Inverter System Capacity into the EIM PGE understands that its 5 MW, 1.25 MW-hr grid-connected lithium ion battery inverter system (BIS) located at the Salem Smart Power Center has the potential to participate in the nascent energy imbalance market. Should this transpire, controls and control software will need to be researched and implemented. This would be accomplished in the context of eventually optimizing the BIS use against other competing use cases such as the present highest value use which is frequency support. Inasmuch as bidding the SSPC battery into the EIM would be a first attempt – PGE will need to explore the best methods to do this in collaboration with PGE Power Operations either on a manual or automated basis. Doing this successfully would bring intellectual capability to PGE engineers and software programmers that will be well placed as even more batteries or other types of energy storage devices connect to the grid and also have a role in the EIM.	OE	15,000
49. Analytical Pilot Study - Demand Impact Forecasting & Validation Technology This project is an analytical pilot study and reporting of estimates related to precision and applicability of demand impact forecasting and validation technology within the PGE service territory for each individual customer with the aggregate program at an hourly resolution. The effort will also include historical cross-validation and back-casting (purposefully challenging a model with real data and a known outcome to see how well the model predicts the outcome) to measure the expected performance of the models. If successful, PGE will be equipped to decide on the viability of consumer-level forecasting for the purposes of using residential DR programs as a reliable peak load reduction and shifting option, and on the viability of performance-based individualized compensation measures. PGE will research how best to securely share interval data with TROVE Data Science of DR participating customers, specifically those involved in the Residential Pricing Pilot. TROVE will use this data as well as their own third-party attribute data to build predictive models at the customer-level to measure demand impacts for each historical event and future events for the upcoming year.	OE	125,000
50. WSU – Power Engineering Energy Innovation (ESI) Center Data Access Washington State University's ESI Center brings together research faculty, business leaders, and governmental organizations to address the technological challenges inherent in the demand for renewable, clean and reliable energy. The center consists of more than 30 WSU faculty members. Thirteen are in the core areas of power, energy, and computer science. More than twenty are in sociology, economics, psychology, communication, and public policy - helping bridge the gap between science and society. The center also collaborates with a wide range of government and industry partners. The center's focus areas include renewable energy; social and economic incentives; information collection, delivery, and analysis; decision support; efficient use of right-of-way and associated economic issues; and cyber security of the smart grid. Many of these topics are of interest to PGE especially in light of Oregon’s SB 1547 mandate for PGE to achieve 50% renewable power by 2040. PGE participation in ESI can lead not to just data and information access but also to collaborative research that is co-funded by larger granting institutions such as the US DOE. PGE believes that participation in this opportunity will better position its staff to implement smart grid applications with special emphasis on renewable power penetration into the Pacific Northwest grid. This combination would benefit PGE’s overall customer base.	SG	25,000
51. Collaboration with BPA Innovation Technology Program (up to 15 Topics) PGE staff has long been aware of Bonneville Power Administration’s (BPA) extensive research capabilities and funding as part of its Innovation Technology Program. In recent years, BPA	SG	100,000

PGE R&D Projects for 2018		
Brief Description	**Topic**	**2018 $**
management has invited PGE staff to sit in on annual reviews of the entire program. PGE staff have also participated on joint BPA-PGE research projects to ensure mutual leverage of strengths via the partnership. With this partnering foundation set in place, this research project seeks to identify PGE interest in BPA research projects where PGE would increase its presence on select topics to provide knowledge and funding on specific projects to BPA staff and in return, PGE would leverage, on behalf of its customers BPA's much larger R&D budget as embodied in its Innovation Technology Program. At present, PGE staff have identified up to 15 topics where such mutual leverage will likely be useful. Examples of potential collaboration areas include: Home Battery Systems; MW Scale Battery Energy; Demand Response; Cold Spray – Hydroelectric Turbines and Advanced Wind Generation Forecast Error.		
52. <u>Low Income, City of Portland Multi-Family Heat Pump Water Heater Demo</u> PGE and the City of Portland will participate in a collaborative demonstration to assess the ability to incorporate highly efficient heat pump water heaters in multi-family buildings that cater to the low-income segment of our customer base. This project will assess the logistics of helping foster a higher penetration of this equipment as well as provide objective costs and resulting benefits that derive for the residential and commercial customers of PGE's low-income segment	SG	30,000
53. <u>Exploring Digital Personal Assistants to Lower Utility Transaction Cost</u> The advent and penetration of the internet of things (IoT) is increasing and more often than not can find potential cost savings for PGE customers in their use. Example of technologies includes Digital Personal Assistants: o Google Home o Amazon Echo The objective of this research is to develop a system that enables a digital personal assistant to report-out on routinely-requested transactional data, for example: o Train the Personal Assistant to develop skill so that customers can pay a bill or ask a routine question via a personal assistant o Explore how personal assistants may be used to decrease costs of transactional requests via PGE's CSO organization Partners for this effort include o Technology vendor (e.g., Google, Amazon) o Programming support (e.g., Accenture) o PGE Corporate planning and IT teams o Eventually PGE's CSO organization	SG	40,300
54. <u>Exploring Use of Non-Intrusive Customer Load Monitoring Devices (3-years)</u> This project seeks to explore the "metering of the future and (non) intrusive load monitoring": Examples of technologies: o MIT gadget that disaggregates energy use at household level o Sense gadget that does the same thing o Neurio home energy monitor o Others likely to be discovered at CES 2017 The research objective(s) are divided into two timeframes: o Near term: ▪ Compare results of data against PGE AMI data ▪ Test customer interface and engagement platform ▪ Install technology that could be used in future Hackathons o Longer term: ▪ Determine if/how these types of devices may supplant need for AMI ▪ Consider if/how these data may be used instead of modeled data via Energy Tracker	DG	40,000

PGE R&D Projects for 2018		
Brief Description	**Topic**	**2018 $**
• Match results of data with customer engagement/programs • To create tailored recommendations based on *empirical* (as opposed to modeled) results o Target partners for this research include: ▪ Technology vendor ▪ Evaluation firm (if not PGE internal staff) ▪ Customer/employee ▪ PGE Meter Team, others		
55. Load Shifting at small scale using HVAC with Ice Storage Capability This project will investigate integrating energy storage using ice with HVAC. Examples of recent technologies derived from market monitoring include: o Ice Energy has a storage integrated HVAC Solution o Another more recent article on Ice Cub The research objective(s): o Explore new technology (ease of installation, quality, cost, experience, value) o Determine savings to be realized, if any, under TOU and/or if net metering were evolved to RVOS o Identify target household, if any, within PGE Service Area for demonstration Expected partners for this project include: o Technology vendor o Evaluation firm o Customer/employee ▪ Ideally a home with solar ▪ Maybe also small business? o PGE or Consultant or University partner as subject matter expert o HVAC installation vendor?	SG	60,000
56. Practicality of 100% Solar Roofing Material in the Pacific Northwest Solar photovoltaic (PV) applications continue to increase in penetration and decrease in cost. Thus, PGE, on behalf of its customers will explore leading edge offerings in this market to ensure the Company and its customers have good knowledge and understanding. An example of a recent PV application technology was announced by Tesla (https://www.tesla.com/solar) where it will be offering a whole roof solar product. The objective(s) of this research include: o Assessing cost effectiveness compared to usual & customary roofing o Assess physical durability o Need for maintenance and to what extent o Safety issues, if any o Customer and market acceptance	RP	40,000
57. Support & Participation in Updating End Use Load Research Studies The Pacific Northwest – as a region has been a notable national leader in energy efficiency for the last four decades. Much of this work has been based on consumer uses of electricity and the devices that convert electricity to modern conveniences such as lighting, refrigeration, consumer appliances of all types, HVAC, to name just a few. For the Pacific NW, the formal research database for consumer data end use loads is now easily 30 years old and very dated. Consumer behavior in electricity use and the electrical devices/appliances/gadgets that use electricity to deliver the end use or convenience, has evolved. This project allows PGE to engage with regional players such as utilities, consumer groups, NGOs and other stakeholders to share the costly proposition that supports updating of regional End Use Load Research Studies. PGE customers will benefit due to the funding leverage whereby PGE's contribution will be combined with joint funding from other regional utilities and related institutions.	SG	120,000
58. Pre-Feasibility Study – Low Head Hydrokinetic Device	RP	25,000

PGE R&D Projects for 2018		
Brief Description	**Topic**	**2018 $**
PGE has done preliminary due diligence on a potentially viable low head hydrokinetic power generator. The unit under consideration comes in two power capacity sizes, requires at least 15 feet of depth and on the order of 1.5 meters/sec of water velocity. PGE has interest in the unit capable of 400 kW of power generation. The manufacturer is a Canadian Company, whose technology has been licensed by Boeing in an exclusive 25 year arrangement to market, sell and deliver turnkey hydrokinetic energy farms deriving power from the flow velocity of a river. The device under consideration for testing and demonstration has been emplaced in the St. Lawrence River for four years with two of the years under power generating conditions and the remaining two years "free-wheeling" to assess wear and tear. In this demonstration, it appears that migrating fish species actively avoid the unit and survive interaction. This project seeks to characterize a possible location for demonstrating this device (or equivalent) as part of PGE's power generating infrastructure. PGE believes a location just downstream of Pelton Dam appears adequate. This project will produce definitive bathymetric (underwater topography) measurements as well as the vertical and horizontal velocity profiles of the Deschutes River bank to bank cross-section at the location of interest. It is possible to also use the cooling canal at the Boardman Power Plant for this same purpose. It is likely that over a two period there will be significant licensing work and other impact analyses to accommodate use of this device in either a riverine or canal setting.		
Total		**$2,753,300**

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Production O&M

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bradley Jenkins
Aaron Rodehorst

February 28, 2017

Table of Contents

I. Introduction

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

A. My name is Bradley Jenkins. My position at PGE is Vice President, Power Supply Generation. I am responsible for all aspects of PGE's Power Supply Generation. My qualifications are included at the end of this testimony.

My name is Aaron Rodehorst. My position at PGE is Senior Analyst, Regulatory Affairs. My qualifications are included at the end of PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support the operations 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 2018 test year O&M expenses related to PGE's generating plant operations as compared to actual 2016 O&M expenses.

Q. What are PGE's goals for plant operations and maintenance?

A. Our primary goals for plant-related activities are to manage our Generation plants in a safe, reliable, and economically competitive manner while maintaining compliance with all local, state, and federal 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 necessary investments in our Generation plants.

Q. How is the remainder of your testimony organized?

A. Our testimony has four additional sections. In Section II, we discuss PGE's Generation resources and their recent performance. In Section III, we discuss our forecast of 2018 test year Generation O&M expenses. We then summarize our request in this filing in Section IV and present Mr. Jenkins' qualifications in Section V.

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 2018 test year?

A. Yes. Confidential PGE Exhibit 701 lists PGE's generating resources and their expected average energy output as modeled under normal hydro conditions for PGE's initial 2018 Net Variable Power Cost (NVPC) forecast.[1]

Q. Have PGE's long-term power supply resources changed significantly since the UE 294 general rate case?

A. Yes. In Order No. 15-356, Docket No. UE 294, the Public Utility Commission of Oregon approved the addition of the Carty Generating Station (Carty) in customer prices, if placed into service by July 31, 2016. PGE met that deadline when Carty went into service on July 29, 2016.

B. Plant Performance

Q. What are PGE's goals for Generation plant performance?

A. The performance and availability of PGE's generating resources are top priorities for the Generation organization. As a long-term goal, we target plant performance and availability in the top quartile of an industry peer group. On a year-to-year basis, realized plant availability is a key factor in evaluating the Generation organization.

Q. How have PGE's thermal plants performed in 2015 and 2016?

A. In 2015, the majority of PGE's thermal plants experienced no major forced outages and exhibited high availability. Thermal Generation was higher than normal for most of our

[1] Discussed in PGE Exhibit 300

thermal plants due to low natural gas prices and the timing of hydro availability. Because of a warm spring in 2015, runoff came earlier than normal and did not coincide with the summer peak, requiring increased dispatch of thermal facilities to meet loads.

In 2016, the majority of PGE's thermal plants continued to perform very well, experienced no major forced outages, and maintained a high availability. Similar to 2015, we had mild winter and spring temperatures at the beginning of the year causing the economic displacement of the Boardman generating plant. Towards the end of 2016, high amounts of rain led to increased hydro availability displacing the majority of our thermal resources.

Confidential PGE Exhibit 704 provides historical 2013 through 2016 thermal plant availability and forced outage rates reported quarterly by PGE to the North American Electric Reliability Corporation (NERC), and finalized annually.[2]

Q. Were there any exceptions in 2015 and 2016?

A. Yes, just one plant. Beaver generating plant's forced outage rate is higher in 2015 and 2016 due to unplanned maintenance work:

- In 2015, Unit 3 had an unplanned hot gas path inspection following a routine inspection, Unit 6 experienced excessive internal oil leaks requiring immediate troubleshooting and repair, and Unit 7 (steam turbine) had excessive vibration on the generator requiring disassembly and repair of the end blocking of the rotor windings.
- In 2016, Unit 2's Major Inspection was extended due to discovery work identified during repairs creating an unplanned outage extension, Unit 7 (steam turbine)

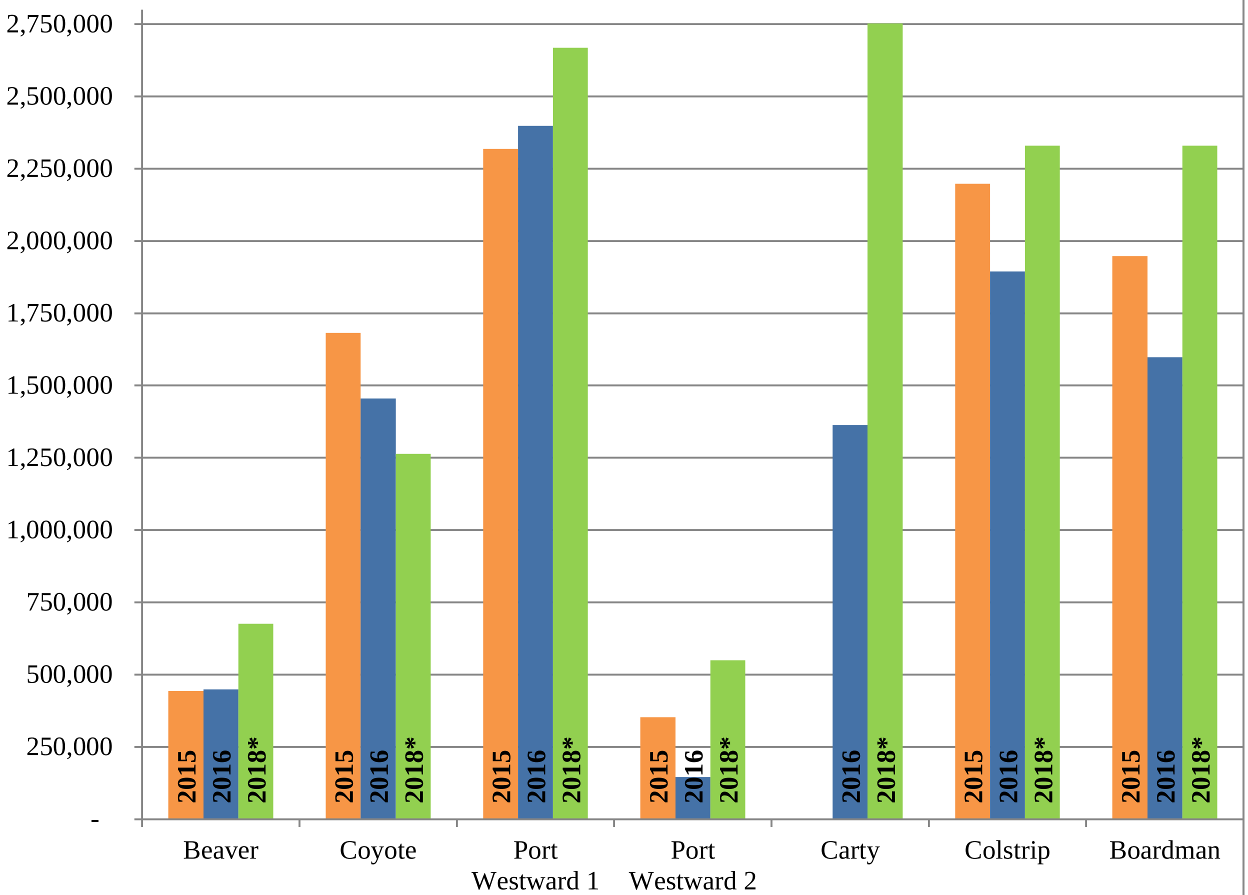
[2] Forced Outage Rates reported to NERC are not equivalent to the forced outage rate methodology applied in PGE's Net Variable Power Cost (NVPC) forecast. See PGE's Minimum Filing Requirements included as part of PGE's NVPC forecast for details on the forced outage rate methodology employed in MONET.

experienced vibration issues requiring a rebalancing, and Unit 8 was forced out most of the year due to compressor damage and evaluation of repairs.

Q. How does the 2018 expected Generation for PGE's thermal resources compare to previous years?

A. Figure 1 below summarizes actual thermal Generation for 2015 and 2016, and PGE's current 2018 forecast for each of our existing thermal resources. Thermal Generation is expected to increase for our thermal resources in 2018 relative to 2016, primarily due to weather normalization and forecasted low fuel prices, which we expect to contribute to increased dispatch. PGE Exhibit 300 presents our 2018 NVPC forecast.

Figure 1: PGE Thermal Resource Generation (MWh)



Data Source:
*2018 based on initial NVPC forecast presented with this filing
2016 based on the 2016 EGR&D YTD Report presented in Docket No. UM 1294 (Monthly Power Cost Report)

III. Generation Plant O&M

A. Generation Plant O&M Expenses

Q. What are the changes in PGE's plant O&M between 2016 and 2018?

A. Table 1 below summarizes the changes in total Generation Plant O&M expenses. These amounts include adjustments for emissions control chemical costs.

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

O&M Expenses	2016 Actuals	2018 Test Year	Delta	Annual % Change
Labor	$39.4	$43.3	$3.9	4.8%
Non-Labor	$81.5	$85.6	$4.1	2.5%
Major Maintenance Accruals	$12.1	$16.3	$4.2	16.0%
Subtotal	$133.0	$145.1	$12.1	4.5%
Information Technology (IT)	$12.4	$14.6	$2.3	8.7%
Total	**$145.4**	**$159.8**	**$14.4**	**4.8%**

**May not sum due to rounding.*

Q. How do labor and non-labor plant O&M expenses change from 2016 to 2018?

A. Labor-related plant O&M is projected to increase by approximately $3.9 million. This increase is due to labor cost escalation (discussed in PGE Exhibit 400) and an increase to the number of Full Time Equivalent employees (FTEs) discussed below. Non-Labor related plant O&M, including the Major Maintenance Accruals (MMA), is projected to increase by approximately $8.3 million. The major drivers of these increases are summarized in Section B below.

Q. What do IT costs represent?

A. IT costs represent expenses that are directly assigned and allocated to Generation and that relate to PGE's efforts to develop, operate, and maintain our computer, information, cyber, and communication systems. IT costs are allocated to all operating areas of the company and discussed in detail in PGE Exhibit 500.

B. Generation Plant O&M Expense Major Drivers

1. Non-Labor O&M Expenses

Q. What are the major drivers to non-labor O&M expenses?

A. The major drivers to non-labor O&M expenses are: 1) the increase in Carty O&M expenses, 2) updates to PGE's Major Maintenance Accruals, and 3) non-labor cost escalations.

Q. Please explain the increase in Carty O&M expenses.

A. Carty O&M expenses are estimated to increase by approximately $0.9 million due to the plant being operational for the full year 2018. In 2016, Carty began operations on July 29. Customer prices, however, already reflect Carty's full year budget in accordance with Commission Order No. 15-356.

Q. Please explain the increase in Major Maintenance Accrual (MMA) expenses.

A. PGE's MMA benefits to customers, calculation methodology, and expenses are discussed in detail in Section C below.

Q. What is the increase in non-labor O&M expenses due to non-labor cost escalations?

A. Non-labor O&M expenses are forecasted to increase by approximately $3.1 million in the 2018 test year due to non-labor cost escalations. For non-labor costs, we use escalation rates ranging from 1.66% to 3.11% from *Global Insights, Economic Outlook* dated August 2016. Non-labor cost escalation rates are presented in PGE Exhibit 200.

2. Labor O&M Expenses

Q. What is the change in Generation related FTEs from 2016 to 2018?

A. The projected increase in FTEs is approximately thirty-two across Generation.

Q. What are the main drivers for the increase in Generation-related FTEs?

A. The main drivers of the increase in Generation-related FTEs between 2016 and 2018 are as follows:

- Ten Power Supply Engineering Services (PSES) FTEs. These FTEs will 1) support increasing regulatory requirements, 2) work on PGE's aging assets requiring upgrades and/or replacement, and increased engineering support to maintain aging infrastructure, 3) develop expanded technical expertise needed as new forms of generation are added and control systems are modernized, and 4) ensure that PGE maintains a strong cyber security program. It is important for PGE to fill these positions in 2017 and 2018 to ensure that PGE's capital investments are utilized in an effective and beneficial manner and to allow PSES to properly manage the workload necessary to meet regulatory compliance and cyber security best practices.
- Four Resource Planning FTEs. These FTEs will provide increased support for strategic projects, Renewable Portfolios, and Integrated Resource Planning (IRP). If Resource Planning does not fill these positions, the impacts include, but are not limited to, reduced productivity and quality, long delays in regulatory processes, and reduced opportunity for stakeholder involvement.
- Three Trojan FTEs. These FTEs will support increased Trojan security per Nuclear Regulatory Commission (NRC) Security requirements. PGE is working with the NRC to implement a security staffing that meets their recommendations and industry standards. The NRC has recently completed its assessment of our plan and its conclusions are being disseminated. As a result of the timing, actual staffing may differ from the one submitted for the OPUC review in our 2018 general rate case filing. Nearly all costs associated with these FTEs are reimbursable to PGE through

the settlement claim with the Department of Energy for the Trojan Independent Spent Fuel Storage Installation, approved by the U.S. Court of Federal Claims on July 18, 2013.

- Three Environmental and Licensing Services FTEs. These FTEs will support the increased demands of regulatory compliance, FERC license implementation requirements, and increased outreach requirements related to our fisheries program per the Pelton-Round Butte Fish Committee recommendation.
- Twelve Generation plant and Power Operation FTEs. These FTEs will increase the number of operating crews at Port Westward and support Generation projects, PGE's participation in the Western Energy Imbalance Market (EIM)[3] starting in 2017, and increased plant operations and maintenance for Carty, Pelton-Round Butte, and Beaver.

Additional detail by FTE is provided in PGE Exhibit 702.

Q. Please summarize the FTEs requested for PSES.

A. PSES provides civil, electrical, mechanical engineering, and survey services to PGE's generating plants and related departments. PSES also provides various forms of administrative support, such as records management, drawing control, and project design. As a result of adding new assets (Port Westward II in 2015 and Carty in 2016), continually expanding cyber security, regulatory and reporting requirements, and aging Generation resources, PSES requires six additional FTEs for administrative, engineering, and analyst positions. Four additional FTEs result from the reorganization of surveyors from Property

[3] Discussed in PGE Exhibit 300, Section III, Part C

Services to PSES in the middle of 2016 and the transfer of an Admin Specialist from Hydro Operations to PSES in 2018.[4]

Q. Please summarize the position additions in Resource Planning.

A. The IRP process has materially changed from a cyclical process to one that requires an ongoing level of support. In the past the process was cyclical and involved a two-year planning cycle, in which heavy analysis and documentation was completed in the first year, followed by a less intense stakeholder review process in the second year. The emergence of variable energy in increasing quantities and the portfolio effects between all resources have created new challenges for resource planning and system operators. As a result, the IRP process has evolved to incorporate new resource types, characteristics, and relationships. PGE must increase staffing to be able to keep pace with the complexity of the analysis, communicate information to stakeholders, maintain continuity, and ensure appropriate individual workloads.

Q. Please summarize the remaining FTE additions in Generation.

A. The remaining additional FTEs relate to increased environmental regulatory compliance and license implementation requirements, generating plant operation support, other compliance requirements (e.g., Trojan Independent Spent Fuel Storage Installation), and PGE's participation in the Western EIM. As noted above, detailed information by FTE is provided in PGE Exhibit 702.

[4] The four FTEs transferred from Property Services and Hydro Operations represent a net zero FTE impact company wide and will have no incremental costs to customers.

C. Major Maintenance Accruals

Q. Please explain the major maintenance accrual (MMA) included in fixed O&M costs.

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[5] occur; and 2) it results in an expense that is cyclical and "lumpy" over the years. Due to this, it can be problematic to establish stable prices. To avoid these problems, the Commission approved in Docket No. UE 93 (Order No. 95-1216) an accrual and balancing account treatment for major maintenance costs.[6] The major maintenance accrual is based on a multiple-year forecast of major maintenance activities with an accrual estimate designed to bring the balancing account to zero at the end of the multiple-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. Properly matching the major maintenance expense to the period of operation benefits customers by reducing intergenerational inequities in prices to customers. In addition, normalizing the costs reduces the frequency of rate changes because it eliminates the need to

[5] The benefits are the generation and use of electricity by customers
[6] Order No. 95-1216 approved an MMA for Coyote Springs. Subsequent Commission orders approving MMAs include: PW1 (UE 262, OPUC Order No. 13-459), PW 2 (UE 283, OPUC Order No. 14-422), and Carty (UE 294, OPUC Order No. 15-356)

file nearly annual rate cases or deferred accounting applications to capture the significant increases or decreases in major maintenance costs.

Q. What items are included in the MMA?

A. Major maintenance events occur based upon maintenance intervals established under the company's plant maintenance contracts. Generally, the timing is dependent upon a facility's capacity factor (hours run / hours in period). Listed below are examples of natural gas 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, 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.
- SR Catalyst Replacements.
- Auxiliary Boiler Maintenance.

Q. How does PGE calculate the MMA?

A. We forecast five years of the expected operational run of our thermal plants using the MONET model and, based on hours of plant operation, we forecast the timing for the major maintenance activities. The total maintenance costs over the five year period are averaged to obtain the annual major maintenance expense.

Q. For which thermal plants are MMAs included in the 2018 test year plant O&M costs?

A. For the test year 2018 PGE will continue to have MMAs for Port Westward 1 and 2, Coyote Springs, and Carty. In addition to these, PGE is proposing an MMA for the Colstrip generating plant.

Q. Please explain PGE's proposal to create an MMA for Colstrip.

A. Colstrip Units 3 and 4 operate on a three-year maintenance outage schedule. This creates a pattern where maintenance outages occur in two of every three years leading to large variances in costs from one year to another. To address the cyclical and "lumpy" nature of these costs and for the other reasons discussed above we propose creating an MMA for Colstrip.

Q. What is the cost impact of creating an MMA for Colstrip?

A. Creating an MMA for Colstrip would increase the forecasted total MMA amount for the 2018 test year by approximately $2.3 million. However, we propose reducing the MMA amounts for our other thermal plants in the 2018 test year such that the net increase in total MMA after adding Colstrip would be less, or approximately $1.0 million.

Q. What is the total MMA amount included in the 2018 test year plant O&M costs?

A. The 2018 test year total forecasted MMA expense is $16.3 million, increasing by $4.7 million over 2016 actuals. The major drivers for this variance are the $2.7 million increase in the Carty MMA due to having the plant operational for a full-year in 2018 and the $2.3 million increase due to adding the Colstrip MMA. Similar to Carty non-labor O&M expenses, the increase in the Carty MMA has a minimal actual cost impact to customers because Carty's full annualized budget was placed in rates in accordance with Commission Order 15-356 (UE 294). Based on the current level of the balancing accounts for the MMAs and the latest five-year forecast for Coyote Springs and Port Westward 2 we reduced the annual accrual amounts by approximately $0.9 million, partly offsetting the increase due to adding the Colstrip MMA. Major maintenance accrual calculations are presented in PGE Exhibit 703.

IV. Conclusion

Q. Please summarize your request for Production O&M in this filing.

A. We request that the Public Utility Commission of Oregon approve PGE's forecast of $159.8 million in Production O&M costs in the 2018 test year. This represents a $14.4 million increase from 2016 costs due primarily to non-labor costs escalations, increases in plant and power operations O&M expenses, and labor O&M expenses.

V. 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 (TVA). 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. I was appointed Vice President of Power Supply Generation in September of 2015. Today, I am responsible for over 3000 MWs of wind, solar, hydro, and thermal Generation at 15 Generation facilities, as well as the Trojan Independent Spent Fuel Storage Installation. I am also an Air Force veteran with 9 years of military experience as a Systems Analyst.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
701C	PGE Generating Resource Summary
702	PGE Full Time Employees Descriptions
703	PGE Major Maintenance Accrual Calculations
704C	PGE Thermal Plant Forced Outage Rate and Availability 2013-2016

EXHIBIT 701C

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Dept.	Dept. Description	Description	Basis for Position(s)	FTE
GENERATION				**32.0**
16	Power Operations	Energy Market Settlement Analyst	PGE will join the Western Energy Imbalance Market in the latter half of 2017 and the Market Operator will be sending PGE large settlement files on a frequent basis. Two additional FTEs are required to perform this work.	2.0
16	Power Operations	Energy Market Policy Analyst	Required to monitor the policy and rule changes implemented by the Western Energy Imbalance Market. The position will be needed early in 2017 to assist Market Trials prior to live participation in the Western Energy Imbalance Market in the latter half of 2017.	1.0
62	Trojan	Independent Spent Fuel Storage Installation (ISFSI) Technician	Required to perform security, operating, maintenance, and administrative functions at the Trojan ISFSI. The ISFSI technicians will report to the ISFSI Supervisor and are responsible for the safe storage of spent nuclear fuel from the Trojan Nuclear Plant. The ISFSI technicians are being added in response to recent NRC Security Inspector comments highlighting the need for additional staff to adequately cover security duties required in federal regulation. Nearly all costs are reimbursable to PGE through the DOE settlement claim for the Trojan ISFSI.	3.0
86	Port Westward 2	Generation Technician	Required to support progression from four to five operating crews and maintenance. Having the additional FTEs will also reduce the use of contractors during PW2 annual outages.	3.0
88	Carty	Generation Technician	To better align gas plants, a planner scheduler was added to all gas plants in 2015. That 1 FTE count was not added to Carty total head count resulting in Carty being one Generation Technician short. Adding this FTE is required to ensure that plant operations and maintenance are being done in an effective and efficient manner.	1.0
161	Pelton-Round Butte	Maintenance Supervisor	Pelton Round Butte operation and dispatch changed significantly over the past 5 to 10 years with the plant being cycled more frequently and seemingly relied upon more for ancillary services as opposed to primarily being base loaded in the past. This position is required to manage critical asset maintenance and coordinate maintenance support and outage planning services in support of plant operations.	1.0
Various	Beaver	Temporary Hourly Positions	Required to reduce overtime and are partially offset by savings from this reduction. Although the three temporary hourly positions appear to be an increase, this is because PGE opted to contract out the work these positions would have done in 2016. As such, 2016 outside services is over budget while temporary labor is under budget. PGE continues to expect to need this support and has budgeted three FTEs for 2018.	3.0
551	Power Supply Engineering Svcs	Surveyors	Reorganization of surveyors from Property Services to PSES in the middle of 2016. FTE impact is a net zero change company wide and will have no incremental cost to customers.	3.0

551	Power Supply Engineering Svcs	Cyber Security Engineer	With the additional and existing Industrial Control System (ICS) generation assets (i.e. assets that run plant generators), the ever increasing workload will require a deeper level of cyber security engineering support. The cyber engineer position is required to ensure PGE generation sites are able to respond to the ever changing cyber security threats. Each engineer is working to balance operational requirements with defending our current technologies from cyber-attacks.	1.0
551	Power Supply Engineering Svcs	Cyber Security Analyst	With the current cyber-attack rate at existing and future industrial Control System (ICS) generation assets, PGE has implemented capital projects associated with a Network Intrusion Detection System (NIDS). These recent software and hardware investments require an analyst position to tune and develop the NDIS system to ensure all PGE generation sites have proper protocols to respond to cyber-attacks.	1.0
551	Power Supply Engineering Svcs	Compliance Specialist	Required to assist in understanding, interpreting, communicating, and implementing PGE compliance with North American Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) regulatory standards.	1.0
551	Power Supply Engineering Svcs	Analyst	Required for additional support of PGE's new Reliability, Performance, and Monitoring (RPM) Center initiated in 2016. The RPM Center brings in house the plant and asset performance monitoring historically provided by General Electric's "Smart Signal" service. Additionally, the RPM Center will provide an extra level of vigilance as PGE begins more frequent cycling of generating plants.	1.0
551	Power Supply Engineering Svcs	IT Analyst	Will function as a dedicated generation resource for resolving IT issues at Generation facilities. With the ever expanding role of IT based systems at PGE, a dedicated resource is required to ensure that issues at remote Generation facilities are addressed in a timely manner.	1.0
551	Power Supply Engineering Svcs	Admin Specialist	transfer from Hydro Operations. FTE impact is a net zero change and will have no incremental cost to customers.	1.0
551	Power Supply Engineering Svcs	Technical Writer Specialist	Required to assist with the development and maintenance of over 200 generation procedures, including Generation Fleet, Environmental, Cyber Security, Compliance, Reliability, and plant specific procedures.	1.0
554	Generation Projects	Project Manager / Senior Project Engineer	Required to provide expertise for engineering reviews, project coordination, and project management. The Generation Project department is planning for the next five years while continuing to support current projects, intracompany requests for support of projects, and evaluation of new and evolving technologies to support future projects. In analyzing the timeline of the current IRP, currently proposed renewable RFP, and future RFPs, and the timeframe to develop new supply- and demand-side resources, Generation Projects has identified a gap in staffing that threatens the ability of the group to successfully deliver complex and strategic for our customers.	1.0

	Integrated Resource Planning	Analyst	Required to provide strategic and technical analysis, including economic evaluations or resource options needed to meet the electric energy needs of PGE customers. They will also provide analysis to support recommendation regarding several regulatory processes, including, but not limited to, the IRP and Competitive Bidding (RFP). With the increased workload due to the emergence of variable energy in increasing quantities and the portfolio effects between all resources, current employees are consistently working more than 40 hours per week affecting the work quality and significantly increasing the risk for mistakes. Additionally, important work is being deferred or dropped due to lack of bandwidth to complete critical tasks. Several options to fill the business needs, minimize impacts and overcome the challenges were evaluated, including contractors, sunset positions, cross-training, and long-term temporary positions. None provide the necessary support to maintain quality and efficiency over the long term.	3.0
556	Integrated Resource Planning	Project Manager	Required to facilitate management and coordination for the models to support evaluation of technologies, locational deployment and use cases for all resources, as well as development of the documentation and materials necessary to transparently communicate the information produced through the IRP and related process. Several options to fill the business needs, minimize impacts and overcome the challenges were evaluated, including contractors, sunset positions, cross-training, and long-term temporary positions. None provide the necessary support to maintain quality and efficiency over the long term.	1.0
841	Environmental and Licensing Services	Project Controls and Compliance Specialist	Required to develop, implement, research, and support project control for PGE's environmental projects, ensure their implementation in an economical manner, and coordinate compliance, communication and interaction among various PGE departments and groups. The position will also develop department budgeting and staffing strategy and schedules based on projected projects going through funding process.	1.0
842	Eastside Biological Services	Technician, Environmental Communication	The Pelton-Round Butte Fish Committee, comprised of 22 state and federal agencies and NGOs have raised concerns about the growing outreach needs related to our fisheries program, and that current staffing isn't sufficient to meet that without affecting the biological program. Currently there is an active adversarial group, the Deschutes River Alliance (DRA) on the Deschutes River that opposes the Pelton Round Butte fisheries and water quality program. DRA is currently suing PGE under the Clean Water Act. The DRA has a very active and effective public relations campaign. PGE's communication/PR hasn't been sufficient given the increased negative campaigning. This position was created to provide a dedicated person, located on the Eastside, to increase our outreach efforts in the community. Before this, the Eastside Biological staff tried to fill the gap, but this increased workload was interfering with their ability to complete FERC required tasks. The risk of not providing increased outreach is that DRA's influence would grow, adding other NGOs and community members to their supporters threatening PGE's investment in the Selective Water Withdrawal fish collection facility.	1.0

844	Environmental Compliance and Licensing	Environmental Specialist	Required for multi-media environmental support for eastside non-hydro generation sites (Biglow Canyon, Boardman, Carty, Coyote Springs, Tucannon), with emphasis on air quality and waste management. Increased regulations and activities include coal combustions residuals, ODEQ changes to air quality permitting, and general environmental support for generation facilities.	1.0

Exhibit 703 is voluminous in size,
provided in electronic format only

EXHIBIT 704C

Confidential

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Transmission and Distribution O&M

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bill Nicholson
Larry Bekkedahl

February 28, 2017

Table of Contents

I. Introduction

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

A. My name is Bill Nicholson. I am Senior Vice President of Customer Service and Transmission and Distribution.

My name is Larry Bekkedahl. I am Vice President of Transmission and Distribution.

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 explain our increasing capital spending reflected in Portland General Electric's (PGE) 2018 test year. This additional spending will allow us to accommodate increased customer demand on the Transmission and Distribution (T&D) system, and maintain reliability and other system goals through the implementation of T&D asset management strategy. In addition, we also discuss T&D's operations and maintenance (O&M) costs for the 2018 test year, which includes a request to modify the current storm deferral to more effectively normalize storm restoration costs in PGE's prices.

Q. What are T&D's primary goals?

A. Our primary goals are to:

- Provide safe and reliable energy delivery services to our customers;
- Cultivate a corporate culture that improves employee and public safety;
- Enhance efficiency and increase customer value by deploying new techniques, technologies, industry best practices, and process improvements; and
- Ensure compliance with applicable regulations, including those addressing T&D grid reliability and operations.

Q. How is the remainder of your testimony organized?

A. The remainder of our testimony is organized into the following sections:

- Section II: Strategic Capital Improvements
- Section III: Transmission and Distribution Operations and Maintenance
- Section IV: Conclusion
- Section V: Qualifications

II. Strategic Capital Improvements

Q. Why is PGE planning to increase its capital investment in T&D?

A. We are increasing our investments due to increasing customer-driven capital work and to improve the T&D system to keep it safe and reliable. In addition, we are 'strengthening' the power grid to better prepare for earthquakes, cyber-attacks, and other threats. We are also replacing or upgrading equipment nearing the end of its life and redesigning portions of the T&D system to improve reliability. All of these capital improvements are intended to meet mandates and goals related to the reliability, safety, environmental stewardship, and cost effectiveness of the T&D system.

Q. What changes does PGE face in the T&D operating environment?

A. The T&D organization faces many changes, including:

- Increasing reliability expectations of our customers;
- Increasing regulatory and compliance demands along with safety and environmental concerns;
- An aging asset fleet, which results in more reactive work to address service failures, as opposed to proactive management of system risk;
- Intensifying storms and storm response requirements;
- Increasing amount of customer work, due to a thriving economy. There is also a more complex construction environment, due to strong regional growth and tightening regulations (e.g., jurisdictional coordination and permitting challenges); and
- Employee retirements, which can result in a loss of institutional knowledge.

Q. How will T&D address these changes?

A. We are already addressing many of these changes by increasing labor resources and by developing a more robust and proactive T&D asset management strategy that:

- Directs capital spending where those investments more effectively support customer requirements and demands of the T&D system; and
- Matches overall spending and staff to customer needs.

Q. What are the types of capital improvements?

The capital improvements are in the following categories:

- Customer-driven capital work; this includes continuous improvement projects which are discussed later in our testimony.
- Strategic capital improvements for risk reduction in the T&D system; this includes PGE's Smart Grid initiatives.[1]
- Compliance with relevant regulations (i.e., National Electric Service Code [NESC] and North American Electric Reliability Corporation [NERC]); this applies to both customer-driven capital work and our strategic capital improvements for risk reduction.

A. Customer-Driven Capital Work

Q. What do you mean by customer-driven capital work?

A. Customer-driven capital work refers to those capital investments that are a direct result of customers' requests (e.g., road widenings, new customer connections, and infrastructure improvements) and are needed as a result of our growing customer base.

Q. What customer-driven work are you seeing as a result of the growing customer base?

[1] See PGE's 2016 Smart Grid Report in OPUC Docket No. UM 1460 for details on Smart Grid initiatives.

A. We are seeing a continuing increase in new customer connections.

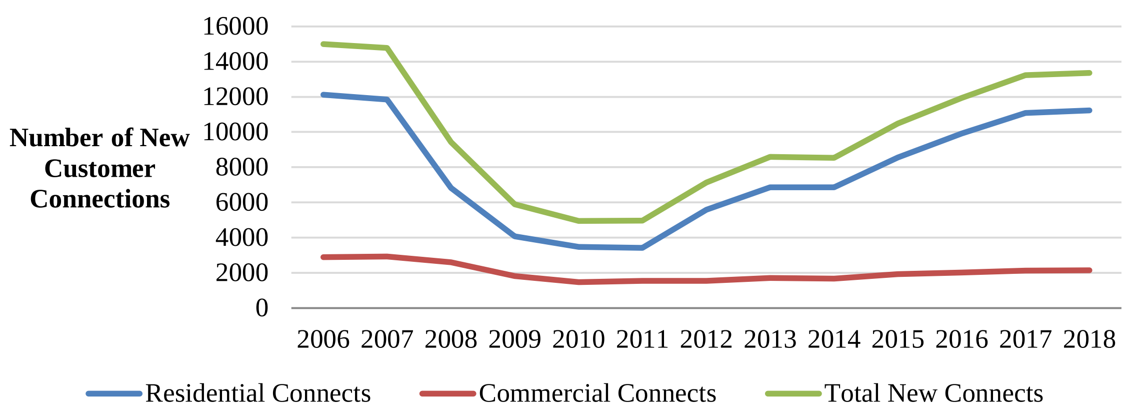
Q. Please define new customer connections.

A. New customer connections consist of new electrical infrastructure designed, engineered, and constructed to connect PGE's electrical system to industrial facilities, commercial buildings, or residential homes where no electrical service previously existed.

Q. Please describe the growth of new customer connections.

A. Growth in new customer connections generally follows economic expansion. The recent recession, beginning in December 2007, had a major impact on PGE's new customer connections. As seen below in Figure 1, new connections fell 66% from 2007 to 2011. Since the economy recovered, new customer connections grew rapidly, increasing by an annual rate of 20% from 2011 to 2016. From 2015 to 2016, new customer connections grew 14%.

Figure 1
New Customer Connection Trend



Q. What is PGE's forecast for new customer connections?

A. PGE forecasts continued growth of 12% from 2016 to 2018, to approximately 13,300 new connections. PGE Exhibit 1200 provides further details regarding customer growth.

Q. Given PGE's forecast for new customer connections, what challenges does T&D face in meeting the increased customer work?

A. There are several challenges that PGE's T&D organization faces when planning and executing customer work, including labor resources, changes in the permitting process, and traffic congestion.

1. Labor Resources – At the same time that customer-driven capital work has begun to increase after the end of the recession, we are experiencing a growing number of retirements from our distribution union workforce.
2. Permitting Process – Over the last few years, the permit process has become increasingly complex and impacted the completion of customer work. Customer work that previously did not require a permit now requires one. In addition, restrictions have been imposed on when and how the work is conducted, which increase costs. For example, certain city requirements constrain the time of day when PGE may do the work, mandating that the work be done at night or restricted to certain days (due to traffic, noise, and other considerations). These impositions can also conflict with one another and make managing and completing customer work more difficult.
3. Traffic Congestion – Traffic congestion has affected PGE crews' ability to timely respond to outages. In a recent report to Governor Kate Brown, the Transportation Vision Panel noted that congestion in the Portland metro area, especially during peak hours, has had major impacts on the economy and created challenges for commuters and businesses.[2] They reported that "[o]n average, metro area commuters spend 52

[2] https://visionpanel.files.wordpress.com/2016/05/one-oregon-final-report-web-version2.pdf

hours per year stuck in traffic, a 13[%] increase compared to five years ago." This is also shown in a report that ranked Portland's commute as the 16th worst in the nation.[3] Similarly, the Oregon Department of Transportation noted, in August 2015, that highways are reaching and exceeding capacity. This congestion adds time to and a delay in PGE crews completing their work.

Q. Will hiring more work crews help overcome the challenges regarding the increased customer-driven capital work?

A. Yes. Increasing the capital-based labor for customer-driven work is the primary way we will respond to the increased demand. In addition to the customer-facing workforce or personnel, we are hiring additional support personnel. To address the challenges T&D is facing above, PGE is strategically hiring FTEs (described further in Part C):

- With the economic recovery and increasing customer connects, PGE is ramping up its union distribution workforce. We plan on adding 19 union distribution workers by 2018 to address limited labor resources. In addition, T&D is strategically placing them in PGE's service territory, which will improve response time to outages by reducing their time in traffic congestion.
- PGE created a new department, Line Prerequisite Coordination, and is hiring FTEs to help manage the permitting processes that are required prior to starting customer work.

In addition, PGE is also hiring employees to help execute the new Customer Service and T&D (CST&D) continuous improvement projects. The goal of the new CST&D Continuous Improvement team is to: 1) identify and continually refine key T&D processes to monitor

[3] http://www.autoinsurancecenter.com/traffic-jammed.htm

and improve, and 2) continue Next Wave stabilization.[4] The need for this work continues because large projects such as the Western Energy Imbalance Market (Western EIM),[5] Customer Engagement Transformation (CET),[6] and T&D's asset management strategy will continue to impact T&D over the next several years and will require changes to existing processes.

In addition to meeting increased new customer connections, we are adding employees to perform essential infrastructure work.

Q. Please explain the infrastructure work.

A. We are building new substations to serve fast-growing areas such as Hillsboro, the South Waterfront, and Central Eastside. This infrastructure work is important to keep the system operating reliably for all customers. In addition, we are replacing aging and heavily loaded substations to mitigate the risk of customer outages. This infrastructure work is described below in Part B.

B. Strategic Capital Improvements for Risk Reduction

Q. Earlier, you stated that T&D has developed a more robust and proactive asset management strategy. Why did you develop this new strategy?

A. We developed this new strategy because T&D's operating environment is rapidly changing. As stated earlier, some of these changes include reliability expectations of our customers, regulatory and compliance demands, an aging asset fleet, and storms and storm response requirements.

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[4] Next Wave is the final phase of T&D Transformation that was discussed in OPUC Docket Nos. UE 283 (PGE Exhibit 900), and UE 294 (PGE Exhibit 800). T&D Transformation is a subset of the 2020 Vision Program, wherein PGE is implementing process improvements and replacing a large number of software programs with enterprise applications.

[5] The Western EIM is discussed in PGE Exhibit 300, Section III, Part C.

[6] CET is discussed in PGE Exhibit 900.

The organization decided to evaluate its longstanding approach to asset management in 2012. To conduct this evaluation, T&D hired a third-party assessor, Black & Veatch (B&V). B&V reviewed T&D's asset management practices and capabilities by conducting a Publicly Available Specification 55 (PAS-55) assessment of T&D.[7] B&V is an endorsed assessor approved to undertake PAS 55 assessments by the Institute of Asset Management (IAM).

Q. What were the results?

A. B&V's evaluation found that our asset management practices "compare favorably with B&V's experience at other utilities, but opportunities for improvement and greater consistency exist."

Primarily, B&V recommended that T&D would benefit from a more proactive and risk-based approach to managing its asset base. Specifically, B&V recommended that T&D develop:

- A stronger capability with risk management approaches, methods and practices;
- A stronger strategic framework and plan for managing the T&D asset base; and
- The organizational infrastructure required to support asset management within T&D.

Q. How did PGE respond to B&V's evaluation?

A. In response to B&V's recommendations, the T&D organization created the Strategic Asset Management department (SAM). SAM develops an annual T&D risk assessment and associated portfolio of recommended risk reduction projects. It also supports the development of T&D's broader annual capital improvement plan.

[7] PAS-55 was published by the British Standards Institution via its Institute of Asset Management. In 2014, PAS-55 became the basis for the ISO 55000 Asset Management Standards.

Q. Please explain SAM's risk assessment approach.

A. SAM developed a risk assessment methodology that uses best industry 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, environmental, and cost efficiency) and supports customer demand.

Q. What is the objective of SAM's methodology?

A. The objective of SAM's methodology is to consider the negative impacts of service failure on:

- System reliability;
- Public and worker safety;
- Environmental stewardship; and
- Efficient expenditure of funds.

SAM identifies system improvements that demonstrate maximum value to customers in terms of risk reduction. The types of projects include:

- Asset replacement by proactively replacing infrastructure that is operating beyond its life and thus creating reliability, safety, environmental, and cost threats for customers;
- System reconfiguration by shifting loads in the system or reconfiguring system designs to better manage load and can reduce the impacts of service failures on customers should they occur; and
- Grid modernization by installing new types of advanced technologies that can help PGE increase reliability and meet new customer demand (e.g., PGE's Smart Grid initiatives).

Q. How does SAM evaluate risk?

A. SAM analyzes data to determine where in the T&D system there is likely to be a high rate of consequential service failures, evaluated as follows:

- Likelihood of a service failure – The likelihood of a service failure is derived using a data-driven assessment of the age and condition of T&D's vital assets. SAM also evaluates historical rates of externally-driven service failures in the T&D system (e.g., failures due to storm and tree events).
- Consequence of service failure – The consequence of service failures is assessed by looking at the electrical loading on the affected assets, the potential outage durations that customers would experience should a failure occur, and the economic effects of such an outage on customers. SAM also considers additional impact factors related to environmental contamination, safety concerns, and PGE direct costs to respond to outage events.

Using this method, SAM assessed the majority of PGE's T&D asset base between 2013 and 2015, and released its first draft T&D Risk Register in 2016. SAM's risk assessment and project identification process will be repeated on an annual basis, now that the base models, tools, and processes have been assembled.

Q. What is a Risk Register and how is PGE using it?

A. The Risk Register is a compilation of significant assets in the T&D system, indicating their likelihood of service failure and their consequence of service failure. PGE remediates risks by proposing projects that address high concentrations of risk, as identified in the Risk Register. Projects are prioritized for execution based on their risk reduction potential, the value of the proposed risk reduction work, and implementation constraints. There are several types of projects generally resulting from the Risk Register approach. They include:

- Substation Upgrades/Rebuilds: Replacement of aging assets in critical substations;
- T&D Upgrades/Rebuilds/Reconfigurations: Replacement of aging and environmentally hazardous assets, and the reduction of excessive loads;
- Distribution Automation: Installation of automated feeder switches to reduce switching time and outage durations;
- Undergrounding and Tree Wire: Redesign and strengthening of the distribution system in areas prone to storm-related outages; and
- Communication System Upgrades/Rebuilds: Replacement of aging assets.

Q. What are the primary reliability risks associated with PGE's T&D system?

A. SAM has identified significant reliability risks in the T&D system related to aging and heavily loaded substation assets, aging cable in the distribution system, and external causes of services failure in the distribution system (weather and vegetation events, etc.).

When examined geographically, reliability risk is heavily concentrated. For example, 75% of PGE's substation risk is concentrated in 41% of T&D substations. Distribution system risk is more concentrated, with 1% of line segments generating 75% of line risk. This is important as this risk impacts our distribution service quality.

Q. What are your projected expenditures to reduce risk in the T&D system?

A. We estimate approximately $111.2 million[8] of capital expenditures in 2017 to upgrade PGE's T&D Network and increase system reliability for our customers. As shown in Table 1, the three largest projects include two from the Risk Register, T&D Substation Reliability

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[8] This number is fully loaded but does not include Allowance for Funds used During Construction (AFDC).

Upgrades and the Underground Cable Replacement Program; and PCB Transformer Testing and Replacements.

Table 1
2017 Capital Expenditures

Capital Projects	$Millions
1. T&D Substation Reliability Upgrades[9]	$60.2
2. Underground Cable Replacement Program	$16.8
3. PCB Transformer Testing and Replacements	$16.7
4. Other[10]	$17.5
Total Capital Projects	**$111.2**

Q. Please describe T&D's Substation Reliability Upgrades.

A. T&D's Substation Reliability Upgrades replace aging assets in critical substations and make up the bulk of the risk reduction work currently in process. The specific work was selected based on risk level, organizational readiness to implement, and system operating constraints. This work will standardize and bring resiliency to some of the highest risk assets within the substation fleet, reducing risk for customers and increasing system reliability. The scopes of work include total rebuild or select asset upgrades (e.g., communication infrastructure and control houses, transmission line protection, distribution switchgear, transformers, etc.). Out of PGE's 186 substations, SAM identified 69 in the Risk Register as high risk. If a substation is rebuilt, old equipment is often not replaced with the same type of equipment. Implementation of current standards requires the installation of equipment that adds resiliency to the substation, such as improved load-balancing and monitoring, and seismic

[9] This includes the following five projects: T&D Substation Reliability Upgrades, Rivergate North Substation Rebuild, Harborton Reliability Project, Tabor Control Enclosure Upgrades, and Orient Substation Capacity Addition.
[10] Other capital expenditures include mobile transformer purchases, vehicles and capital equipment, distribution automation, Supervisory Control and Data Acquisition system replacement, arc flash mitigation, and West Union line addition.

upgrades. Load growth potential is also assessed to determine whether the substation should be configured to accommodate the addition of transformers or feeders in the future.

Q. Can you give an example of a substation rebuild?

A. Yes. Elma, one of our oldest substations, and the third most risky substation in our T&D Risk Register, will have work completed in 2017. Located in Salem, Elma was built in 1949 and consists of two 57kV transmission sources, two distribution power transformers, and four 13kV distribution feeder circuits. Most of the equipment inside the substation is over 40 years old. During a peak summer loading condition, both distribution power transformers and three of the four 13kV distribution feeders are loaded beyond seasonal limits. During an outage, no redundant capacity exists at Elma, or at other adjacent substations, to maintain service; thus, customers are left unserved for extended durations. The inability to provide N-1 redundancy[11] exposes up to 2,100 customers to prolonged outages for the loss of a distribution power transformer, and almost 800 customers are exposed for a sustained distribution feeder outage. Additionally, the substation has no real-time monitoring of equipment loadings and/or operational status, leaving the PGE System Control Center with no outage status until reported by customer calls or visual verification by a PGE crew.

Upon completion, all antiquated substation equipment will have been replaced. The replacement of both distribution power transformers will result in Elma substation achieving N-1 redundancy for all substation transformer and distribution feeder contingencies; if an outage occurs on either of the two transformers or any of the four Elma distribution feeders, customers affected by the outage can be shifted to the other Elma transformer, other Elma

[11] N-1 redundancy is a form of resilience that ensures system availability in the event of system failure.

feeders, or to feeders of other adjacent substations. The addition of two metal-clad switchgear enclosures, each replacing a substandard 13kV distribution box structure, will result in a reduction of risk associated with outages caused by animal intrusions, will achieve improvements in PGE employee safety conditions, and will result in a "future-ready" substation that can accommodate additional load with minimal substation reconfiguration. Additionally, customers will no longer be subjected to prolonged outages due to a lack of Supervisory Control and Data Acquisition (SCADA) telemetry.

Q. Please describe T&D's Underground Cable Replacement Program.

A. T&D's Underground Cable Replacement Program replaces aging and heavily loaded cables that pose reliability risk to customers and the system. SAM's Proactive Cable Program has been in operation since 2015 and was PGE's first T&D risk reduction initiative. We launched the program to respond to concerns about escalating failures on cable installed in the 1960s, 1970s, and 1980s. SAM's Proactive Underground Cable Replacement program replaces high risk cable before it fails. This program operates in tandem with T&D's long-standing Reactive Underground Cable Replacement program, which replaces cable after it fails.

Q. Please describe T&D's PCB Transformer Testing and Replacement Program.

A. PCB Transformer Testing and Replacement involves the testing and removal of distribution line transformers that have any detectable PCBs in environmentally sensitive areas, and above 50 ppm in non-environmentally sensitive areas. PGE established the PCB program to align with an advanced notice of proposed rulemaking issued by the Environmental Protection Agency (EPA) in April 2010.[12] Removing PCB transformers reduces the risk of

[12] A copy of the EPA advanced proposed rule is PGE Exhibit 801.

PCB exposure to human and environmental receptors in the areas in which these transformers are located.

PCB testing was introduced in PGE's 2016 general rate case (Docket No. UE 294).[13] Since our early 2015 filing, T&D has formed a project management team for the program along with supporting personnel (see PGE Exhibit 802) and began replacement efforts in 2016. We decided to test first so that we could create a scope for the program.

Prior to implementation of the program, PGE had forecast that 11,000 transformers would need replacement. After testing 10,236 transformers, PGE revised the forecast slightly to 10,738 transformers (see Table 2, below). As the program continues in 2017, PGE plans to test 10,000 transformers and replace 2,000 annually.

Table 2
Transformers Replacement Forecast (Program Total)

Critical Area Transformers		**Non-Critical Area Transformers**	
Total Number of Transformers	Estimated Number of Replacements	Total Number of Transformers	Estimated Number of Replacements
8,652	6,354	60,561	4,384
		Total Number of Transformers to Test	**69,213**
		Total Number of Transformers to Replace	**10,738**

Q. What additional capital work will T&D perform in 2018?

A. In 2018, we will begin additional T&D projects targeted at high risk distribution segments, and communications systems.

C. Full Time Equivalent Employees

Q. How is PGE investing in labor resources to meet demand and sustain PGE expertise?

[13] PGE filed UE 294 in February 2014.

A. PGE is hiring 169 additional FTEs along with contract labor between 2016 and 2018 to address the higher and on-going levels of T&D activities. T&D requires additional FTEs to help meet several challenges, including:

1. Increasing workload – In general, with the increasing amount of both customer and capital work, T&D requires more administrative, engineering, and specialist support. For example, an increase in the workforce means that more project and construction managers are needed to manage the additional employees, oversee contractors and maintain quality control of work. Increases in linemen translate to increases in storeroom resources to maintain the 2:1 ratio of crews to storeroom personnel. This ensures that there are enough storeroom resources to support line crews and maintain stock room efficiency.
2. Increases in overtime – The increase in workload has resulted in increased overtime hours. In 2016, PGE incurred almost $12.4 million in labor overtime costs from both contractors and PGE employees, a 5% increase over 2015. One cause of overtime is the permitting for customer-driven capital work, discussed above in Part A. Since the majority of permits now require construction at night, labor costs increase and crews have to now work longer days. Hiring additional distribution employees will reduce overtime.
3. Maturing workforce – Over the next three years, PGE will see a large number of experienced employees retire. PGE must replace these employees to keep continuity, maintain system reliability, and address the increase in customer work. By hiring proactively, PGE ensures that there is both a knowledge transfer and time to train the new employees, allowing for effective succession planning. This is important as

succession planning allows employees to develop the skills deemed necessary from experienced employees who are performing the work at higher levels of responsibility.

Q. What are the specific FTE increases?

A. PGE Exhibit 802 provides detailed information on the additional positions. The vast majority of the FTEs are for capital work. Summary descriptions for the FTE increases include:

- Ninety FTEs to support strategic capital improvements identified in the T&D Risk Register as described in Part B, above. Examples of the job functions for these employees include specialized design for transmission and engineering, service and design project managers (SDPM), substation operations and engineering, and support staff such as contract management and fleet and garage operations.
- Approximately fifty-seven FTEs to support the increase in customer-driven capital work as described in Part B, above. Job function examples are Journeymen and Working Foreman Linemen, SDPMs to manage new customer connection projects, specialists to build capacity on the Geospatial Information Services (GIS), and service and design teams.
- Seven FTEs are required for compliance-driven activities. Complying with NERC standards requires additional FTEs as substation upgrades are executed and new substations require O&M support. In addition, FTEs are needed: 1) to address low service clearance within PGE's service territory to maintain compliance with NESC; and 2) for the new Joint Use Inspection program to support the inspection of electric

poles and associated communication attachments that are required to be compliance with the NESC.

- Approximately seven FTEs are needed for continuous improvement projects. These FTEs will help improve processes and create efficiencies in support of the distribution business and will support the following departments: Metrics, Field Technical Services, and T&D Project Services.
- Six FTEs are required for PGE's participation in the Western EIM, beginning October 1, 2017.
- Three FTEs are needed for engineering responsibilities that are part of PGE's Smart Grid initiatives. As PGE moves out of the planning stages of its Smart Grid Initiatives, these FTEs are needed to begin the design, engineering, construction and deployment of these initiatives.

Q. Are you also using contract labor?

A. Yes. PGE uses a balanced approach of contractors and internal labor to implement capital work. Using contractors allows us to address a number of labor needs, including, but not limited to: short-term assignments, specialized knowledge that may not be available in our market or at our wage levels, and for staffing up on projects that have a finite time frame and a need for a short-term influx of personnel.

We will continue to hire contractors to support over half of our capital construction work. The Underground Cable Replacement and the Proactive PCB Transformer Replacement Program will use contractors for this short-term work that is repeatable, programmatic, and easily measurable. Contractors will also be used for building many of our substations because this work is turn-key, fixed-price bid work, and the scope can be clearly defined.

Q. Why is PGE not using contract labor for the incremental FTEs?

A. Regular FTEs are needed to perform ongoing and integral work to support our T&D operations, as those activities exist now and are expected to continue into the future. More specifically, there are four reasons why internal labor is the better choice for the positions requested:

1. <u>Long-term need for these positions</u> – This work is not well suited to a contractor because these resources are required for the long term. Full "onboarding" for a contractor can take as long as 160 hours, and this takes time away from other important tasks. We also lose resources in hiring, training, and certifications when we have to replace a contractor. We develop our employees with the expectation that they will continue to be part of our T&D team, and the time invested creates more value for PGE and for customers.
2. <u>Scarcity of specialized skills</u> – Finding contractors that have the specialized skills or expertise for certain areas of the system is becoming increasingly difficult. Due to this scarcity, qualified contractors are selective in the type of jobs they perform, or where they perform them; so finding available and qualified candidates that are willing to perform certain jobs in our area is difficult.
3. <u>Nature of the position</u> – These positions should not be contracted as they are part of our core business. PGE employees should understand how the T&D system is built so they can support and maintain it into the future. Also, by filling supervisory positions internally that oversee contractor resources, PGE can maintain quality assurance and quality control of work on an ongoing basis.

4. Cost of contracting can be prohibitive for the amount of work requested – Due to the technical skills required for the work and the scarcity of these skills in the labor force, the hourly rates that qualified contractors demand have increased. Given these rates, where the new FTEs requested are replacing contractors, the total labor cost may actually decrease. In addition, overtime pay for a contractor is at double the hourly rate. This contractor hourly rate includes benefits, loadings, and margins. However, for PGE internal labor, only the wage is doubled.

Q. As you are increasing the T&D FTE employees, are you also increasing the amount of contractor work?

A. Yes. As listed in Table 3, the amount of contractor work is increasing along with PGE labor to support the increase in capital work, as well as to continue our O&M activities. However, the contractor work is limited in duration, so when work, such as PCBs have been eliminated from all transformers or substation rebuilds, PGE will have the flexibility to scale back the number of contractors.

Table 3
Comparison of T&D Labor and Contractor Costs* (Millions)

Labor Categories	2016 Actuals	2018 Forecast	Variance 2018-2016
PGE Labor	$100.3	$119.1	$18.8
Non-PGE Labor[14]	$103.3	$126.6	$23.3
Total	**$203.6**	**$245.7**	**$42.1**

** Costs include both capital and O&M.*

[14] A portion of these costs include both labor and non-labor elements (e.g., materials, supplies, etc.) that cannot effectively be separated.

III. Transmission and Distribution Operations

A. Operations and Maintenance Expenses

Q. What are your O&M costs for the 2018 test year?

A. As shown below in Table 4, T&D O&M costs decrease during the period by 2.9%, while T&D Information Technology (IT) O&M costs increase by 16.1%, resulting in an overall increase of 1.2%.

Table 4
Summary of T&D O&M Expenses (Millions)

	2016 Actuals	2018 Test Year	Variance 2016 - 2018	Average % Change
T&D Labor	$49.8	$50.6	$0.7	0.7%
T&D Non-Labor	$54.7	$47.9	$(6.8)	(6.4)%
T&D O&M (excluding IT)	**$104.5**	**$98.5**	**$(6.0)**	**(2.9)%**
T&D IT	$26.7	$36.0	$9.3	16.1%
Total T&D O&M*	**$131.2**	**$134.5**	**$3.2**	**1.2%**

** Numbers may not sum due to rounding.*

Q. What accounts for this cost change?

A. As shown in Table 5, non-labor is the driver for the forecasted $6.0 million decrease in O&M costs, excluding IT.

Q. How do you explain the decrease in O&M costs?

A. The reduction in O&M costs is the result of two factors:

- 2016 actuals include a mid-December storm that was not covered by the storm reserve (discussed below) because: 1) it did not fully qualify as a Level III storm, and 2) the storm reserve had been depleted by previous Level III storms (i.e., if the mid-December storm had been a level III storm, it would still have been reflected in 2016 actuals, as discussed in Part B, below).

- The increase in customer work and investment in system reliability (described in Section II, above), causes a shift in post-2016 costs from O&M to capital. This shift also affects T&D labor, which is otherwise subject to increases in FTEs and cost escalations. PGE Exhibit 400 provides additional detail on labor cost escalation.

Q. What do the IT costs represent?

A. They represent costs allocated to T&D relating to PGE's efforts to develop, operate, and maintain our computer, cyber, information, and communication systems. IT costs allocated to T&D are discussed in PGE Exhibit 500.

B. Distribution Service Quality

Q. Does PGE provide service quality reports to the Public Utility Commission of Oregon (OPUC) at the Distribution level?

A. Yes. Through 2016, PGE was required to submit an annual Service Quality Measure Report (SQM) in accordance with Commission Order No. 97-196. In addition, PGE has a continuing requirement, under OAR 860-023-0151, to report on its reliability performance. Specifically, PGE reports its performance on System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI). PGE submitted the most recent report in 2016 for performance year 2015.

Q. What are SAIDI, SAIFI, MAIFI, and CAIDI?

A. SAIDI is the total amount of time, during a year, that the average customer is without power, measured in minutes. SAIFI is the average number of times a customer experiences an outage during a one-year time period. MAIFI is the average number of momentary outages a customer experiences during a one-year time period. In addition, Customer Average

Interruption Duration Index (CAIDI) is the average outage duration that any given customer would experience; CAIDI can also be viewed as average restoration time. PGE reported its CAIDI performance through 2016 as part of its SQM reporting.

Q. How has PGE performed on the reliability indices mentioned above?

A. As shown in Table 5, PGE has been meeting OPUC performance thresholds for SAIDI, SAIFI, and MAIFI. However, PGE performance has suffered since 2013 due to higher than normal weather activity and outages caused by aging infrastructure, vegetation, and wildlife (e.g., squirrels). In 2015 and 2016, we exceeded the 150 minute threshold established by the OPUC for CAIDI.

Table 5
Three-year Weighted Averages and Penalty Threshold Limits

Year	SAIDI (minutes)	SAIFI (occurrences)	MAIFI (occurrences)	CAIDI (minutes)
2016	97	0.59	1.14	163
2015	75	0.48	1.2	156
2014	95	0.70	1.4	135
2013	62	0.5	0.9	52
OPUC Level 1 Penalty Threshold[15]	105	1.2	5.0	150

Q. What caused PGE's results to increase?

A. The contributing issues causing PGE's CAIDI results to increase are weather, technology, service territory vehicle traffic, and line crew overtime.

- Weather – PGE is experiencing a high volume of small, high intensity, short duration storms that do not quite meet the criteria to be excluded from reliability indicators.[16] In mid-December 2016, the severe weather combined with traffic gridlock on the

[15] This threshold applies prior to the 2016 performance year.
[16] Storms that reach the level of major storms are excluded from CAIDI performance. These weather-related outages combined with a limited number of union distribution crews had the largest effect on CAIDI. These storms were primarily high intensity, short duration wind events which caused damage to remote areas of PGE's distribution system. Remote locations are difficult to access for restoration, contributing to an increase in CAIDI.

roads and highways impacted the ability of our line crews to gain access to storm-related outages, increasing outage durations and creating a second year in which PGE exceeded the CAIDI threshold.

- Technology – While implementation of the Advanced Metering Infrastructure and Outage Management System decrease outage response durations, the integration with and adaptation by employees to other technologies have resulted in certain inefficiencies, which have temporarily lengthened our outage response times and impacted CAIDI performance. In response, we continue to implement the multiple changes associated with these new technologies and work to refine new skill, procedure, and responsibility requirements related to the systems, to which employees are adapting. These complexities have also led to the revised schedule for the CET roadmap as described in PGE Exhibit 900, Section IV, Part A.
- Service territory vehicle traffic – As stated previously in Section II, Part A, traffic congestion has impacted our crews' ability to travel to outages. In addition, cities, such as City of Portland, require PGE to perform more work during the night time hours as they do not allow lane closures during the day on major roads. This requires PGE to perform more planned work at night, increasing overtime per employee and reducing the number of employees available to take outage calls.
- Available Line Crews – As PGE performs more work in the evening hours, fewer line crews are available for afterhours outage restoration work. This negatively impacted the availability of line crews to respond to the larger number of outages in 2015 and 2016.

Major Storms

Q. Did PGE experience any major storms in 2016?

A. Yes. In 2016, PGE experienced two Level III storms in the fourth quarter (and experienced a third storm that nearly qualified as Level III) resulting in approximately $4.5 million in storm damage costs, exceeding PGE's 2016 storm accrual of $2.0 million.

Q. How did PGE determine these storms should be classified as Level III storms?

A. Based on the criteria agreed upon in OPUC Docket No. UE 215, PGE determined that the storms mentioned above met the criteria for a Level III classification and that the funds collected for major storms will be used to offset 2016 costs associated with those Level III storms.

Q. Please describe the current storm accrual as approved in Docket No. UE 215.

A. Per Commission Order No. 10-478, PGE collects $2 million annually for use against future Level III storm costs. The annual accrual is based on a rolling 10-year average of Level III storms, adjusted to reflect present value costs.

Q. Is PGE proposing to update its major storm accrual based on the current 10-year rolling average?

A. Yes. Due to an increase in the 10-year rolling average for Level III storm costs, PGE proposes to increase the storm accrual rate to $2.6 million annually as detailed in PGE Exhibit 803.

Q. Since the storm accrual's inception in 2011, how has the amount accrued compared to actual Level III storm costs?

A. Through 2015, PGE accrued $10 million for major storm damage restoration. At year-end 2015, however, PGE had a zero balance due to offsetting Level III storm damage costs in

2014 and 2015. Lastly, as stated earlier, Level III storms in 2016 caused $4.5 million in damage, exceeding PGE's 2016 accrual of $2 million.

Q. Would negative balances be typical outcomes if you consider a longer period of time?

A. Based on actual storm restoration activity since 1995, and assuming a similar mechanism was initiated any year beginning after 2004 (i.e., to allow at least 10 years of actual detail to inform the rolling average), most years would result in a negative balance.[17] PGE Exhibit 804 summarizes the derivation of the 10-year rolling averages. It also allows us to see how the reserve account balance would trend given fluctuations in Level III storm activity and different years for initiating the accrual.

Q. Why did you examine different years for initiating the accrual mechanism in PGE Exhibit 804?

A. We did so to see if changing the initiation year has an impact on the general result of negative balances over time.

Q. What conclusions do you obtain from PGE Exhibit 804?

A. There are several conclusions to draw from PGE Exhibit 804:

- Over the period observed, storms have tended to be clustered with periods of calm winters followed by periods of stormy winters.
- There has been at least a two-year lag between the time when storms occur and when their effects can be incorporated into the storm accrual as part of a general rate case.
- Because of this lag, the storm accrual always runs behind the next set of storms, and negative balances will be a typical outcome. In fact, positive balances are only

[17] The storm deferral balance is defined as equal to the previous reserve balance plus the current year's accrual minus the current year's actual costs. For these purposes, a negative balance means that costs exceed the accumulated reserve.

expected if the accrual mechanism is initiated at the beginning of a calm winter period, such as PGE experienced from 2011 through 2013. Although such a calm period allows a positive balance to grow, subsequent storm costs reduce the balance faster than it can be updated for the recent storm restoration activity, and negative balances would ensue.

Q. What does PGE specifically propose with respect to the storm accrual?

A. PGE proposes to continue accruing for costs attributed to Level III storms annually, but if storm costs exceed the amount collected from customers, the balance of accrued funds would become negative, and be offset in subsequent years when damage from Level III storms was less than the accrual amount. Under this accounting treatment, PGE could recover incurred storm costs while occasionally carrying a negative balance in the storm account. Ultimately, this would enable PGE to recover costs during consecutive years of Level III storms just as it does after the first year of a Level III storm. Currently, the balance of the storm damage restoration account does not become negative, which requires a larger reserve or higher annual collection rate from customers to recover the costs of several consecutive years of storms or particularly severe storms.

Q. Has the Commission ever approved a similar accounting treatment for PGE?

A. Yes. The proposed major storm accrual has similar accounting treatment to the major maintenance accruals (MMAs) approved for several of PGE's generation facilities.[18] The MMAs also fluctuate between positive and negative balances as periodic costs offset the accrual and vice versa.

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[18] Coyote Springs, UE-93, PGE Exhibit 600. Port Westward 1, UE 262, PGE Exhibit 300. Port Westward 2, UE 283, PGE Exhibit 300. Carty, UE 294, PGE Exhibit 300.

A similar accounting treatment for major storms has been approved in several other states.[19]

Q. What benefit would this treatment provide?

A. Similar to PGE's previously approved MMAs, the recurring, but irregular nature of Level III storms causes significant swings in storm damage costs. Consequently, the proposed major storm accrual would more effectively normalize the sporadic nature of these costs for purposes of establishing customer prices.

Q. Will PGE adjust the accrual for changes in storm expenses?

A. Yes. PGE will continue to update its 10-year rolling average. The 10-year average amount will be collected in prices and be placed into the major storm accrual account. In a year where there are no Level III outages, PGE will retain the accrued amount as a reserve to be used toward future Level III storm damages.

Q. What costs will be included in the major storm accrual?

A. Only a Level III storm causing damage to PGE's T&D system (and which receives a PGE accounting job number) will be included. PGE will continue to use the criteria identified in Docket No. UE-215 to determine a Level III storm.

Q. Why is Commission support for the major storm accrual important?

A. Commission support for the major storm accrual is important to normalize customer prices despite the volatility of Level III storm damage costs.

[19] Before and after the storm, a compilation of recent studies, programs, and policies related to storm hardening and resiliency. Edison Electric Institute. March 2014.

IV. Conclusion

Q. Please summarize your request for T&D in this filing.

A. We request that the Commission approve PGE's forecast of approximately $134 million (including IT) in T&D O&M costs in the 2018 test year, representing a $3.2 million, or 1.2%, increase compared to 2016 actuals. We request that the Commission approve an increase of $0.6 million to accrue $2.6 million in rates annually for Level III storm damage costs. In addition, we request that the Commission approve 169 union and construction support personnel for the increased capital work. We also request that the Commission approve PGE's proposal to allow the storm accrual balance to have negative balances as well as positive balances so as to more effectively normalize storm restoration costs in PGE's prices.

V. Qualifications

Q. Mr. Nicholson, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Nuclear Engineering from Oregon State University. I completed the Harvard University Program on Negotiation and graduated from the Public Utilities Executive course at the University of Idaho. I am a registered professional engineer in the State of Oregon and I belong to the National Society of Professional Engineers. My employment with PGE started in 1980 as an engineer at the Trojan Plant and I have served in a variety of capacities in Distribution Operations, Generation Engineering and Resource Development. In May 2007, I became Vice President of Customers & Economic Development and in August of 2009, I was appointed Vice President of Distribution. In April of 2011, I assumed my current role as Senior Vice President of Customer Service and Delivery, Transmission and Distribution.

Q. Mr. Bekkedahl, please describe your educational background and 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 Power Delivery executive committee, as a U.S. board member for the International Council on Large Electric Systems (CIGRE), and on the member's advisory committee for Peak Reliability, the Reliability Coordinator for the Western Grid. 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 (USAID) exchange projects in Bangladesh, the Republic of Georgia, and the Philippines.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
801	Federal Register - Vol. 75, No. 66
802	Incremental FTE Positions and Explanations
803	Major Storm 10-Year Analysis
804	Storm Costs and Accrual

safety. We will request approval of the incorporation by reference of the 2009 edition of NFPA 101 from the Office of the Federal Register. We are not aware of any significant changes from the 2006 edition to the 2009 edition.

This document for which we are seeking incorporation by reference is available for inspection by appointment (call (202) 461–4902 for an appointment) at the Department of Veterans Affairs, Office of Regulation Policy and Management, Room 1063B, 810 Vermont Avenue, NW., Washington, DC 20420 between the hours of 8 a.m. and 4:30 p.m., Monday through Friday (except holidays). It is also available at the National Archives and Records Administration (NARA). For information on the availability of this document at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html*. In addition, copies may be obtained from the National Fire Protection Association, 1 Batterymarch Park, Quincy, MA 02269–9101. (For ordering information, call toll-free 1–800–344–3555 or go to *http://www.nfpa.org*.)

Unfunded Mandates

The Unfunded Mandates Reform Act of 1995 requires, at 2 U.S.C. 1532, that agencies prepare an assessment of anticipated costs and benefits before issuing any rule that may result in an expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more (adjusted annually for inflation) in any given year. This rule would have no such effect on State, local, and tribal governments, or on the private sector.

Paperwork Reduction Act

This document contains no collections of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3521).

Executive Order 12866

Executive Order 12866 directs agencies to assess all costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity). The Executive Order classifies a "significant regulatory action" requiring review by the Office of Management and Budget as any regulatory action that is likely to result in a rule that may: (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities; (2) create a serious inconsistency or interfere with an action taken or planned by another agency; (3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in Executive Order.

The economic, interagency, budgetary, legal, and policy implications of this proposed rule have been examined, and it has been determined not to be a significant regulatory action under Executive Order 12866.

Regulatory Flexibility Act

The Secretary hereby certifies that this regulatory amendment would not have a significant economic impact on a substantial number of small entities as they are defined in the Regulatory Flexibility Act, 5 U.S.C. 601–612. This rulemaking would affect veterans and State homes. The State homes that would be subject to this rulemaking are State government entities under the control of State governments. All State homes are owned, operated and managed by State governments except for a small number that are operated by entities under contract with State governments. These contractors are not small entities. Therefore, pursuant to 5 U.S.C. 605(b), this rule would be exempt from the initial and final regulatory flexibility analysis requirements of sections 603 and 604.

Catalog of Federal Domestic Assistance

The Catalog of Federal Domestic Assistance numbers and titles for the programs affected by this document are 64.005, Grants to States for Construction of State Home Facilities; 64.007, Blind Rehabilitation Centers; 64.008, Veterans Domiciliary Care; 64.009, Veterans Medical Care Benefits; 64.010, Veterans Nursing Home Care; 64.011, Veterans Dental Care; 64.012, Veterans Prescription Service; 64.013, Veterans Prosthetic Appliances; 64.014, Veterans State Domiciliary Care; 64.015, Veterans State Nursing Home Care; 64.016, Veterans State Hospital Care; 64.018, Sharing Specialized Medical Resources; 64.019, Veterans Rehabilitation Alcohol and Drug Dependence; 64.022, Veterans Home Based Primary Care; and 64.026, Veterans State Adult Day Health Care.

Signing Authority

The Secretary of Veterans Affairs, or designee, approved this document and authorized the undersigned to sign and submit the document to the Office of the Federal Register for publication electronically as an official document of the Department of Veterans Affairs. John R. Gingrich, Chief of Staff, Department of Veterans Affairs, approved this document on March 1, 2010, for publication.

List of Subjects in 38 CFR Part 51

Administrative practice and procedure, claims, day care, dental health, government contracts, grant programs—health, grant programs—veterans, health care, health facilities, health professions, health records, mental health programs, nursing homes, reporting and recordkeeping requirements, travel and transportation expenses, Veterans.

Dated: April 1, 2010.

Robert C. McFetridge,

Director, Regulation Policy and Management.

For the reasons set forth in the preamble, VA proposes to amend 38 CFR part 51 as follows:

PART 51—PER DIEM FOR NURSING HOME CARE OF VETERANS IN STATE HOMES

1. The authority citation for part 51 continues to read as follows:

Authority: 38 U.S.C. 101, 501, 1710, 1741–1743, 1745.

§ 51.200 [Amended]

2. Amend § 51.200 by removing the phrase "(2006 edition)" each place it appears and adding, in its place, "(2009 edition)".

[FR Doc. 2010–7811 Filed 4–6–10; 8:45 am]

BILLING CODE 8320–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 761

[EPA–HQ–OPPT–2009–0757; FRL–8811–7]

RIN 2070–AJ38

Polychlorinated Biphenyls (PCBs); Reassessment of Use Authorizations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Advance notice of proposed rulemaking (ANPRM).

SUMMARY: EPA is issuing an ANPRM for the use and distribution in commerce of certain classes of PCBs and PCB items

and certain other areas of the PCB regulations under the Toxic Substances Control Act (TSCA). EPA is reassessing its TSCA PCB use and distribution in commerce regulations to address: The use, distribution in commerce, marking, and storage for reuse of liquid PCBs in electric and non-electric equipment; the use of the 50 parts per million (ppm) level for excluded PCB products; the use of non-liquid PCBs; the use and distribution in commerce of PCBs in porous surfaces; and the marking of PCB articles in use. Also in this document, EPA is also reassessing the definitions of "excluded manufacturing process," "quantifiable level/level of detection," and "recycled PCBs." EPA is soliciting comments on these and other areas of the PCB use regulations. EPA is not soliciting comments on the PCB disposal regulations in this document.

DATES: Comments must be received on or before July 6, 2010.

See Unit XIII. of the **SUPPLEMENTARY INFORMATION** for meeting dates and other deadlines associated with the meetings.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPPT–2009–0757, by one of the following methods:

- *Federal eRulemaking Portal*: *http://www.regulations.gov*. Follow the on-line instructions for submitting comments.
- *Mail*: Document Control Office (7407M), Office of Pollution Prevention and Toxics (OPPT), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001.
- *Hand Delivery*: OPPT Document Control Office (DCO), EPA East Bldg., Rm. 6428, 1201 Constitution Ave., NW., Washington, DC. Attention: Docket ID Number EPA–HQ–OPPT–2009–0757. The DCO is open from 8 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The telephone number for the DCO is (202) 564–8930. Such deliveries are only accepted during the DCO's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to docket ID number EPA–HQ–OPPT–2009–0757. EPA's policy is that all comments received will be included in the docket without change and may be made available on-line at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through regulations.gov or e-mail. The regulations.gov website is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the docket index available at *http://www.regulations.gov*. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available electronically at *http://www.regulations.gov*, or, if only available in hard copy, at the OPPT Docket. The OPPT Docket is located in the EPA Docket Center (EPA/DC) at Rm. 3334, EPA West Bldg., 1301 Constitution Ave., NW., Washington, DC. The EPA/DC Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number of the EPA/DC Public Reading Room is (202) 566–1744, and the telephone number for the OPPT Docket is (202) 566–0280. Docket visitors are required to show photographic identification, pass through a metal detector, and sign the EPA visitor log. All visitor bags are processed through an X-ray machine and subject to search. Visitors will be provided an EPA/DC badge that must be visible at all times in the building and returned upon departure.

See Unit XIII. of the **SUPPLEMENTARY INFORMATION** for meeting locations.

FOR FURTHER INFORMATION CONTACT: *For general information contact*: Colby Lintner, Regulatory Coordinator, Environmental Assistance Division (7408M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (202) 554–1404; e-mail address: *TSCA-Hotline@epa.gov*.

For technical information contact: John H. Smith, National Program Chemicals Division (7404T), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (202) 566–0512; e-mail address: *smith.johnh@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be potentially affected by this action if you you manufacture, process, distribute in commerce, use, or dispose of PCBs. Potentially affected entities may include, but are not limited to:

- Utilities (NAICS code 22), e.g., Electric power and light companies, natural gas companies.
- Manufacturers (NAICS codes 31–33), e.g., Chemical manufacturers, electroindustry manufacturers, end-users of electricity, general contractors.
- Transportation and Warehousing (NAICS codes 48–49), e.g., Various modes of transportation including air, rail, water, ground, and pipeline.
- Real Estate (NAICS code 53), e.g., People who rent, lease, or sell commercial property.
- Professional, Scientific, and Technical Services (NAICS code 54), e.g., Testing laboratories, environmental consulting.
- Public Administration (NAICS code 92), e.g., Federal, State, and local agencies.
- Waste Management and Remediation Services (NAICS code 562), e.g., PCB waste handlers (e.g., storage facilities, landfills, incinerators), waste treatment and disposal, remediation services, material recovery facilities, waste transporters.
- Repair and Maintenance (NAICS code 811), e.g., Repair and maintenance of appliances, machinery, and equipment.

This listing is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in this unit could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether this action might apply to certain entities. To determine whether you or your business may be affected by this action, you should carefully examine the applicability provisions in 40 CFR part 761. If you have any questions regarding the applicability of this action to a particular entity, consult the technical person listed under **FOR FURTHER INFORMATION CONTACT**.

B. What Should I Consider as I Prepare My Comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through regulations.gov or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD-ROM that you mail to EPA, mark the outside of the disk or CD-ROM that you mail to EPA, mark the outside of the disk or CD-ROM as CBI and then identify electronically within the disk or CD-ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for preparing your comments.* When submitting comments, remember to:

i. Identify the document by docket ID number and other identifying information (subject heading, **Federal Register** date and page number).

ii. Follow directions. The Agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

iii. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

iv. Describe any assumptions and provide any technical information and/or data that you used.

v. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

vi. Provide specific examples to illustrate your concerns and suggest alternatives.

vii. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

viii. Make sure to submit your comments by the comment period deadline identified.

II. Background

A. What Action is the Agency Taking?

With this document, EPA is issuing an ANPRM for the use and distribution in commerce of certain classes of PCBs and PCB items and certain other areas of the PCB regulations under TSCA. EPA is reassessing its TSCA PCB use and distribution in commerce regulations, 40 CFR part 761, subparts B and C, to address:

1. The use, distribution in commerce, marking, and storage for reuse of liquid PCBs in electric and non-electric equipment.

2. The use of the 50 ppm level for excluded PCB products.

3. The use of non-liquid PCBs.

4. The use and distribution in commerce of PCBs in porous surfaces.

5. The marking of PCB articles in use.

EPA is also reassessing the definitions of "excluded manufacturing process," "quantifiable level/level of detection," and "recycled PCBs" in 40 CFR part 761, subpart A.

B. What is the Agency's Authority for Taking this Action?

The authority for this action comes from TSCA section 6(e)(2)(B) and (C) of TSCA (15 U.S.C. 2605(e)(2)(B) and (C)) as well as TSCA section 6(e)(1)(B) (15 U.S.C. 2605(e)(1)(B)). Section 6(e)(2)(A) of TSCA provides that "no person may manufacture, process, or distribute in commerce or use any polychlorinated biphenyl in a manner other than in a totally enclosed manner" after January 1, 1978. However, TSCA section 6(e)(2)(B) provides EPA with the authority to issue regulations allowing the use and distribution in commerce of PCBs in a manner other than in a totally enclosed manner if the EPA Administrator finds that the use and distribution in commerce "will not present an unreasonable risk of injury to health or the environment." (EPA's authority to allow distribution of PCBs in commerce is limited to those PCB items that were "sold for purposes other than resale" before April 1978 (TSCA section 6(e)(3)(C) (15 U.S.C. 2605(e)(3)(C))). Section 6(e)(2)(C) of TSCA defines "totally enclosed manner" as "any manner which will ensure that any exposure of human beings or the environment by the polychlorinated biphenyl will be insignificant as determined by the Administrator by rule." Section 6(e)(1)(B) of TSCA directs EPA to promulgate rules to require PCBs to be marked with clear and adequate warnings and instructions (15 U.S.C. 2605(e)(1)(B)).

III. Context of this ANPRM

In the 1970s, commercial manufacture of PCBs in the United States ceased. A substantial portion of the PCBs that had already been manufactured were still in use in many areas of the country; in 1976 EPA estimated that of 1.4 billion pounds (lbs.) of PCBs produced in the United States, 750 million lbs. remained in service in the country. Approximately 75% of the PCBs produced were for use as liquids in electrical or industrial equipment (Ref. 1). For some specific types of equipment, such as electrical capacitors, virtually all of the large number of units manufactured and in use contained PCBs, but for other types of equipment, such as electromagnets, only a small number of units contained PCBs (Ref. 2).

TSCA became effective on January 1, 1977. Section 6(e) of TSCA generally prohibited the manufacture, processing, distribution in commerce, and use of PCBs and charged EPA with issuing regulations for the marking and disposal of PCBs. EPA published the first regulations addressing the use of equipment containing PCBs on May 31, 1979 (Ref. 3). Over the 30 years since then, many changes have taken place in the industry sectors that use such equipment, and EPA believes that the balance of risks and benefits from the continued use of remaining equipment containing PCBs may have changed enough to consider amending the regulations.

A. Regulatory History

On December 30, 1977, EPA published a notice in the **Federal Register** stating that implementation of the January 1, 1978 ban imposed by TSCA was being postponed until 30 days after the promulgation of new regulations (Ref. 4). On May 31, 1979, EPA promulgated these regulations (Ref. 3). The regulations found that PCB liquid-filled capacitors, electromagnets, and transformers (other than railroad transformers) met the statutory definition of "totally enclosed," and were exempt from the ban in TSCA section 6(e)(2)(A) on manufacture, processing, distribution in commerce, or use. This EPA finding meant that it was not necessary to specifically authorize the use of these types of PCB-containing equipment. In this same regulation, EPA also authorized, in accordance with TSCA section 6(e)(2)(B), the use of other liquid-filled equipment that was not totally enclosed (railroad transformers, heat transfer systems, and hydraulic systems), based on a finding that the use would pose no unreasonable risk of injury to health or the environment, subject to conditions. One of the conditions EPA imposed on the authorization of most non-totally enclosed uses was a time limit on the use of PCBs at or above the established 50 ppm PCB regulatory cutoff. In the June 7, 1978 (Ref. 5), proposed rule for the use authorizations, EPA discussed its authority and rationale for establishing use limits:

> Section 6(e)(2)(B) of TSCA permits EPA to authorize by rule the manufacturing, processing, distribution in commerce, and use of PCBs in a non-totally enclosed manner if these activities will not present an unreasonable risk of injury to health or the environment. EPA has determined that certain non-totally enclosed PCB use activities will not present an unreasonable risk and proposed to authorize these use activities for a period of 5 years after the effective date of the final rule. At that time, EPA will examine the need for continuing these authorizations.

(Ref. 5, p. 24807)

EPA has not previously undertaken a reassessment. In making this determination to make a reassessment, EPA weighed the effects of PCBs on health and the environment, the magnitude of exposure, and the reasonably ascertainable economic consequences of the rule. This determination is fully discussed in the support/voluntary draft environmental impact statement. These proposed time limits were, with minor modifications, adopted in the final rule:

> Unlike all other activities that may be subject to an authorization under TSCA section 6(e)(2)(B), use activities are not prohibited under TSCA section 6(e)(3)(A). Accordingly, there is no automatic limit to the length of use authorizations. In deciding how long to authorize each use, EPA believes that it should have the opportunity to review each use in a timely way to ensure that there is no unreasonable risk associated with its continuation. In addition, improved technology or development of new PCB substitutes could reduce the need for the authorization. Accordingly EPA proposed a five-year limit on most use authorizations; however, no such limit was proposed on the use authorization for PCBs in electric equipment.

(Ref. 3, p. 31530)

After the May 31,1979, rule was published, the Environmental Defense Fund, Inc., (EDF) petitioned the U.S. Court of Appeals for the District of Columbia Circuit to review the portion of the 1979 regulation which designated the use of "intact and non-leaking" PCB liquid filled capacitors, electromagnets, and transformers (other than railroad transformers) as "totally enclosed." On October 30, 1980, the court decided that there was insufficient evidence in the record to support the Agency's classification of the equipment as "totally enclosed" (Ref. 6). The court vacated this portion of the rule and remanded it to EPA for further action. EPA, EDF, and certain industry interveners petitioned the court to stay the mandate while EPA conducted rulemaking beginning with an ANPRM, and a utility industry group agreed to develop factual information necessary for the rulemaking. The court granted the request for a stay and the text of the court order was published with EPA's ANPRM on March 10, 1981 (Ref. 7). On August 25, 1982, EPA issued a final rule authorizing the use of capacitors, electromagnets, and transformers other than railroad transformers, in accordance with TSCA section 6(e)(2)(B) (Ref. 8). Time limits were imposed on the use of certain types of PCB equipment posing an exposure risk to food and feed. Since 1982 there have been additional rulemakings (e.g., Refs. 9 and 10), which, with certain exceptions, have continued to allow the use of PCB-containing equipment, the passive removal of PCB-containing equipment from use through attrition, and to require the disposal of PCBs and PCB-containing equipment in an environmentally sound manner.

B. PCB Use Authorizations

Currently, under 40 CFR 761.30, the following liquid-filled PCB equipment is authorized for use in a non-totally enclosed manner:

- Electrical transformers.
- Railroad transformers.
- Mining equipment.
- Heat transfer systems.
- Hydraulic systems.
- Electromagnets.
- Switches.
- Voltage regulators.
- Electrical capacitors.
- Circuit breakers.
- Reclosers.
- Liquid-filled cable.
- Rectifiers.

The servicing, in accordance with specified conditions, of the following liquid-filled equipment is also authorized:

- Electrical transformers.
- Railroad transformers.
- Electromagnets.
- Switches.
- Voltage regulators.
- Circuit breakers.
- Reclosers.
- Liquid-filled cable.
- Rectifiers.

Liquid PCBs are authorized for use where they are a contaminant in the following equipment:

- Natural gas pipeline systems.
- Contaminated natural gas pipe and appurtenances.
- Other gas or liquid transmission systems.

There are also use authorizations for certain non-liquid PCBs applications: Carbonless copy paper and porous surfaces contaminated with PCBs regulated for disposal by spills of liquid PCBs. There are other use authorizations for research and development (40 CFR 761.30(j)), for scientific instruments (40 CFR 761.30(k)), and for decontaminated materials (40 CFR 761.30(u)).

However, there are no use authorizations for non-liquid PCB-containing products if they contain PCBs at concentrations > 50 ppm, including but not limited to adhesives, caulk, coatings, grease, paint, rubber or plastic electrical insulation, gaskets, sealants, and waxes.

In 40 CFR 761.35, storage for reuse of authorized PCB articles is allowed for up to 5 years, or longer if kept in a storage unit complying with TSCA or the Resource Conservation and Recovery Act (RCRA) requirements.

C. Distribution in Commerce Regulations

Section 6(e)(2)(C) of TSCA states, "The term 'totally enclosed manner' means any manner which will ensure that any exposure of human beings or the environment to a polychlorinated biphenyl will be insignificant as determined by the Administrator by rule." The definition established by rule in 40 CFR 761.3 is, "Totally enclosed manner means any manner that will ensure no exposure of human beings or the environment to any concentration of PCBs."

EPA has found that the distribution in commerce of intact and non-leaking equipment is "totally enclosed." See 40 CFR 761.20 (Ref. 3, p. 31542). Therefore, no authorization is required for the distribution in commerce for use of intact and non-leaking, liquid-filled electrical equipment, so long as the equipment was sold for purposes other than resale before July 1, 1979. Section 40 CFR 761.20 states:

> In addition, the Administrator hereby finds, for purposes of section 6(e)(2)(C) of TSCA, that any exposure of human beings or the environment to PCBs, as measured or detected by any scientifically acceptable analytical method, may be significant, depending on such factors as the quantity of PCBs involved in the exposure, the likelihood of exposure to humans and the environment, and the effect of exposure. For purposes of determining which PCB Items are totally enclosed, pursuant to section 6(e)(2)(C) of TSCA, since exposure to such Items may be significant, the Administrator further finds that a totally enclosed manner is a manner which results in no exposure to humans or the environment to PCBs. The following activities are considered totally enclosed: distribution in commerce of intact, nonleaking electrical equipment such as transformers (including transformers used in railway locomotives and self-propelled cars), capacitors, electromagnets, voltage regulators, switches (including sectionalizers and motor starters), circuit breakers, reclosers, and cable that contain PCBs at any concentration and processing and distribution in commerce of PCB Equipment

containing an intact, nonleaking PCB Capacitor.

Since then, EPA has gathered information showing measurable emissions of PCBs from some otherwise intact and non-leaking equipment, which is not energized (providing or receiving electricity), to the ambient air (Ref. 11). "Weeps" and "seeps" and other leaks are visual indicators that the distribution in commerce of some of this equipment could result in exposure to humans or the environment to PCBs.

D. PCB Health Effects

The following information about the health effects of PCBs is taken directly from the 1996 EPA document entitled "PCBs: Cancer Dose Response Assessment and Application to Environmental Mixtures" (Ref. 12), which is the source document for the 1997 EPA Integrated Risk Information System (IRIS) file for PCBs. The information is referenced in the 1997 EPA IRIS file for PCBs under heading II.A.2 (Human Carcinogenicity Data), it states in part:

Occupational studies show some increases in cancer mortality in workers exposed to PCBs. Bertazzi et al. (1987) found significant excess cancer mortality at all sites combined and in the gastrointestinal tract in workers exposed to PCBs containing 54 and 42 percent chlorine. Brown (1987) found significant excess mortality from cancer of the liver, gall bladder, and biliary tract in capacitor manufacturing workers exposed to Aroclors 1254, 1242, and 1016. Sinks et al. (1992) found significant excess malignant melanoma mortality in workers exposed to Aroclors 1242 and 1016. Some other studies, however, found no increases in cancer mortality attributable to PCB exposure (ATSDR, 1993). The lack of consistency overall limits the ability to draw definitive conclusions from these studies. Incidents in Japan and Taiwan where humans consumed rice oil contaminated with PCBs showed some excesses of liver cancer, but this has been attributed, at least in part, to heating of the PCBs and rice oil, causing formation of chlorinated dibenzofurans (ATSDR, 1993; Safe, 1994).

A study of rats fed diets containing Aroclors 1260, 1254, 1242, or 1016 found statistically significant, dose-related, increased incidences of liver tumors from each mixture (Brunner et al., 1996). Earlier studies found high, statistically significant incidences of liver tumors in rats ingesting Aroclor 1260 or Clophen A 60 (Kimbrough et al., 1975; Norback and Weltman, 1985; Schaeffer et al., 1984). Partial lifetime studies found precancerous liver lesions in rats and mice ingesting PCB mixtures of high or low chlorine content.

Several mixtures and congeners test positive for tumor promotion (Silberhorn et al., 1990). Toxicity of some PCB congeners is correlated with induction of mixed-function oxidases; some congeners are phenobarbital-type inducers, some are 3-methylcholanthrene-type inducers, and some have mixed inducing properties (McFarland and Clarke, 1989). The latter two groups most resemble 2,3,7,8-tetrachlorodibenzo-p-dioxin in structure and toxicity.

Overall, the human studies have been considered to provide limited (IARC, 1987) to inadequate (U.S. EPA, 1988a) evidence of carcinogenicity. The animal studies, however, have been considered to provide sufficient evidence of carcinogenicity (IARC, 1987; U.S. EPA, 1988a). Based on these findings, some commercial PCB mixtures have been characterized as probably carcinogenic to humans (IARC, 1987; U.S. EPA, 1988a). There has been some controversy about how this conclusion applies to PCB mixtures found in the environment.

(Ref. 13)

In addition to cancer, the 1996 document states, "Although not covered by this report PCBs also have significant ecological and human health effects other than cancer, including neurotoxicity, reproductive and developmental toxicity, immune system suppression, liver damage, skin irritation, and endocrine disruption. Toxic effects have been observed from acute and chronic exposures to PCB mixtures with varying chlorine content" (Ref. 12).

The Agency for Toxic Substances and Disease Registry (ATSDR) Toxicological Profile for PCBs of November 2000 (2000 ATSDR Toxicological Profile) is a more recent review of the toxicity of PCBs. The study's summary of health effects (chapter 2.2) states:

The preponderance of the biomedical data from human and laboratory mammal studies provide strong evidence of the toxic potential of exposure to PCBs. Information on health effects of PCBs is available from studies of people exposed in the workplace, by consumption of contaminated rice oil in Japan (the Yusho incident) and Taiwan (the Yu-Cheng incident), by consumption of contaminated fish, and via general environmental exposures, as well as food products of animal origin....[H]ealth effects that have been associated with exposure to PCBs in humans and/or animals include liver, thyroid, dermal and ocular changes, immunological alterations, neurodevelopmental changes, reduced birth weight, reproductive toxicity, and cancer. The human studies of the Yusho and Yu-Cheng poisoning incidents, contaminated fish consumption, and general populations are complicated by the mixture nature of PCB exposure and possible interactions between the congeneric components and other chemicals.... Therefore, although PCBs may have contributed to adverse health effects in these human populations, it cannot be determined with certainty which congeners may have caused the effects. Animal studies have shown that PCBs induce effects in monkeys at lower doses than in other species, and that immunological, dermal/ocular, and neurobehavioral changes are particularly sensitive indicators of toxicity in monkeys exposed either as adults, or during pre- or postnatal periods.

(Ref. 14)

EPA continues to examine more recent scientific studies on the health effects of PCBs and seeks comments and/or information on the health effects of PCBs available since the 1997 EPA update of IRIS and since the 2000 ATSDR Toxicological Profile. Any proposed or final PCB rulemaking which relies on PCB health effects will use information subject to EPA's rigorous peer-review process.

E. PCB Environmental Effects

The 2000 ATSDR Toxicological Profile for PCBs summarizes the environmental fate, transport, and bioaccumulation of PCBs as follows:

Once in the environment, PCBs do not readily break down and therefore may remain for very long periods of time. They can easily cycle between air, water, and soil. For example, PCBs can enter the air by evaporation from both soil and water. In air, PCBs can be carried long distances and have been found in snow and sea water in areas far away from where they were released into the environment, such as in the arctic. As a consequence, PCBs are found all over the world. In general, the lighter the type of PCBs, the further they may be transported from the source of contamination. PCBs are present as solid particles or as a vapor in the atmosphere. They will eventually return to land and water by settling as dust or in rain and snow. In water, PCBs may be transported by currents, attach to bottom sediment or particles in the water, and evaporate into air. Heavy kinds of PCBs are more likely to settle into sediments while lighter PCBs are more likely to evaporate to air. Sediments that contain PCBs can also release the PCBs into the surrounding water. PCBs stick strongly to soil and will not usually be carried deep into the soil with rainwater. They do not readily break down in soil and may stay in the soil for months or years; generally, the more chlorine atoms that the PCBs contain, the more slowly they break down. Evaporation appears to be an important way by which the lighter PCBs leave soil. As a gas, PCBs can accumulate in the leaves and above-ground parts of plants and food crops. PCBs are taken up into the bodies of small organisms and fish in water. They are also taken up by other animals that eat these aquatic animals as food. PCBs especially accumulate in fish and marine mammals (such as seals and whales) reaching levels that may be many thousands of times higher than in water. PCB levels are highest in animals high up in the food chain.

(Ref. 14)

The 2000 ATSDR Toxicological Profile also summarizes ecotoxicological effects of PCBs in wildlife (Ref. 14). Information in the 2000 ATSDR Toxicological Profile is gathered from experimental studies and field observations of wildlife, specifically outlining PCB effects in fish, bird, and mammal species. The biological responses in wildlife to exposures to individual PCB congeners and commercial PCB mixtures vary widely in these studies, possibly reflecting not only variability in susceptibility among species, but also differences in the mechanism of action or selective metabolism of individual congeners. Noteworthy impacts on fish, birds, and mammals from this collective data include neurological/behavioral, immunological, dermal, and reproductive/developmental effects. Observed PCB effects related to neurological impairment include alterations in central nervous system neurotransmitter levels, retarded learning, increased activity, and behavioral changes. Immunological effects consist of morphological changes in organs related to the immune system, as well as functional impairment of humoral- and cell-mediated immune responses. Dermal effects in species include adverse effects on fins and tails in fish, and abnormal skin, hair, and nail growth in mammals. Lastly, reproductive and developmental impacts consist of increased embryo/fetal loss through effects such as decreased egg hatchability and reduced embryo implantation (Ref. 14).

EPA seeks information on the environmental effects of PCBs that became available after the 2000 ATSDR Toxicological Profile (Ref. 14).

IV. Objective of this ANPRM

The objective of this ANPRM is to announce the Agency's intent to reassess the current use authorizations for certain PCB uses to determine whether they may now pose an unreasonable risk to human health and the environment. This reassessment will be based in part upon information and experience acquired in dealing with PCBs over the past 3 decades. This ANPRM solicits information from the public on several topics to assist EPA in making this reassessment.

Since the Agency first promulgated its PCB use regulations in 1979, EPA's knowledge about the universe of PCB materials has greatly increased. The Agency has gained valuable knowledge and experience regarding the various sources and uses of PCB materials. Over the past 30 years, EPA has had the opportunity to evaluate and draw conclusions about the effectiveness of the PCB regulations in preventing an unreasonable risk to human health and the environment from exposure to PCBs, as well as their economic impact. This document details EPA's observations on why there is reason to make changes in the regulations. At the present time, EPA is investigating whether some authorized uses of PCBs should be eliminated or phased-out and whether more stringent use and servicing conditions would be appropriate. EPA is also re-examining the geographical and numerical extent of PCBs and PCB items, which are subject to the use regulations. The objective of the anticipated rulemaking would be to modify any of the regulations that apply to PCBs or PCB items, as necessary, if these uses present an unreasonable risk to human health and the environment, taking into account conditions as they exist and as they are likely to exist in the future.

EPA seeks information that will be useful in making the findings required by TSCA section 6. By prohibiting the use of PCBs (except in a totally enclosed manner), Congress established a statutory presumption that use of PCBs poses an unreasonable risk of injury to health or the environment. In order to assess whether a use poses "no unreasonable risks," EPA would include an assessment of impacts on the economy, electric energy availability, and all other health, environmental, or social impacts that could be expected from adoption of alternatives to PCBs. There is a list of several questions related to EPA's reassessment in Unit XIV. Responses to the questions will provide EPA with information needed to assist in its reassessment; other information, of course, is also welcome.

EPA recognizes that there may be differences in the maintenance operations, inventories, planning, funding, and budgets for different owners of electrical equipment and does not make any assumptions about these differences. For example, when compared to very large interstate utilities, small municipal and cooperative utilities may have a very different approach to address the replacement of leaking equipment. Where applicable and appropriate, small municipal and cooperative utility responders should provide information about the impacts a phaseout of PCB-containing equipment might have on their operations and their customers. In particular, EPA encourages small municipal and cooperative utilities to take the time to answer the questions in Unit XIV. or otherwise provide details about maintenance operations, inventories, planning, funding, budgets, or any other information related to the cost of addressing the sound environmental management of the PCBs in their equipment and measures they have taken or planned to take and how these measures will help to safely manage their PCBs. EPA also is interested in exploring a range of incentives or programs that might facilitate organizations with limited budgets to remove regulated PCBs and PCB equipment from their systems and facilities.

In this document, EPA is also announcing plans to involve stakeholders in gathering information to inform EPA's determination of the scope of the problem, and EPA's decision on the best ways to address risks that may be present from current PCB use authorizations. EPA will sponsor a series of public meetings around the country to solicit stakeholder comments on this document. Specific information regarding the locations, dates, and times of the public meetings are included in Unit XIII.

V. EPA's Reasons for Reassessing Existing Use and Distribution Provisions

A. Attrition, Aging of Equipment, and Spills

All of the PCB-containing equipment in current use, which has been operating in accordance with the 1979 and subsequent use authorizations, is at least 30 years old. Since the ban on manufacturing in 1979, no new equipment containing PCBs at concentrations greater than or equal to (≥) 50 ppm has been manufactured. The total number of PCB transformers in the United States is decreasing (Ref. 15) but there are still many PCB transformers in use (Ref. 16). Also, all but the most recently manufactured PCB-containing equipment may be nearing the end of its expected useful life, although the useful life of some equipment may have effectively been extended by extensive maintenance and re-building. The useful life of transformers is typically no more than 30–40 years (Ref. 2).

Equipment is increasingly vulnerable to leaks the older it becomes. For example, between 2002 and 2005, two large, aging electrical transformers located on Exxon Mobil's offshore oil and gas platform, Hondo, in the Santa Barbara Channel, leaked nearly 400 gallons of PCB-contaminated fluid. Exxon allowed one of the transformers to leak for almost 2 years before repairing it (Ref. 17).

Several statutes and regulations require reporting of spills of hazardous chemicals, including PCBs, to the United States Coast Guard National Response Center. EPA contacted the National Response Center (Ref. 18) to find out how many PCB spills have been reported historically. The National

Response Center advised EPA that there were a total of 5,578 spills associated with PCBs reported from 1990 through August 19, 2009 (Ref. 19).

B. International Developments

PCBs are persistent chemicals and it is internationally recognized that they pose a risk to health and the environment and need to be removed from use. As of October 6, 2009, 166 countries have signed and ratified, accepted, approved, or accessed the Stockholm Convention on Persistent Organic Pollutants (Stockholm Convention), which among other things requires parties to make determined efforts to phaseout certain ongoing uses of PCBs by the year 2025. The United States is a signatory to the Stockholm Convention but has not yet ratified it (Ref. 20). A similar agreement, which has an earlier date relating to the phaseout of certain ongoing uses of PCBs, is the 1998 Aarhus Protocol on Persistent Organic Pollutants of the 1979 Convention on Long-Range Transboundary Air Pollution, which the United States signed in 1998. As with the Stockholm Convention, the United States is a signatory to the Aarhus Protocol, but has not yet ratified this agreement (Ref. 21).

On September 17, 2008, Canada published PCB ban and phaseout regulations with bans starting in 2009 for high concentration PCBs (Ref. 22). In the Canadian regulations, low-level (< 500 ppm) equipment must be removed from use by 2025.

C. Disposal and Cleanup Costs

EPA anticipates that disposal costs may increase faster than the general increase in inflation or cost of living. The population of PCB-containing equipment is continually decreasing and will never grow or rebound due to the ban on manufacturing. This may make the economics of retaining a presence in the PCB storage and disposal industry potentially less economically attractive for the waste management industry. The numerous disposal options and excess disposal capacity currently present may not be available in the future, so the costs and benefits of continuing to operate aging equipment change in the future. The benefits of continued use of PCB-containing equipment are also diminished by the increasing risk that aging equipment may fail in a manner that releases PCBs to the environment as that equipment reaches the end of its useful life. The cost of cleaning up PCB spills may exceed the cost of reclassifying or disposing of the intact PCB equipment and replacing it with new equipment. The consequences include both the direct costs to the equipment owners in damage, equipment replacement, service interruption, and lost revenue, and also the liability costs of losses to other parties, and compensation and potential fines for damages to human health and the environment. EPA seeks information and comment on how much the possibility of spills and the costs of cleanup affect the decisions of facility owners and operators regarding the management, removal, reclassification, or replacement of PCB equipment.

D. Insurance Costs

EPA believes that the cost of liability insurance for owners of PCB equipment is likely to increase significantly as the equipment continues to age. Insurers have already observed the increased rate of failure in equipment which is approaching the end of its useful life expectancy (Ref. 23). EPA anticipates that in the future there will be continuous increases in the cost of liability insurance to cover all equipment because of numbers of releases and contamination from PCB equipment which is at least 30 years old. EPA seeks comments on the comparison of the cost of future liability insurance with potential costs for testing and reclassification of potentially contaminated equipment either before it has failed or before there has been a determination made to dispose of it. EPA seeks information on historical changes in insurance premiums, as PCB-containing equipment has aged, and any projections of changes in future rates as a result of projected changes in failure rates. EPA also seeks information and comment on the extent to which the availability of commercial liability insurance or self-insurance by facilities affects facility owners' and operators' decisions on how to manage removal or reclassification of PCB equipment that may be nearing the end of its useful life.

E. Hazard Assessment of PCBs

EPA is evaluating the risks from polychlorinated dibenzo-*p*-dioxin (PCDDs) and structurally similar chemicals, such as certain PCBs, through a process referred to as the Dioxin Reassessment (Ref. 24). Polychlorinated dibenzo-*p*-dioxins, polychlorinated dibenzofurans (PCDFs), and some PCBs as molecules are structurally similar and have been shown to have similar impacts on human health and the environment. Also, under certain conditions, the incomplete combustion of PCB-containing materials produces PCDDs and PCDFs, including some of the more toxic congeners. Preliminary indications from the 2003 Draft Dioxin Reassessment are that the toxicity of PCBs in general is higher than the toxicity values that EPA used in developing previous TSCA PCB regulations. Some PCB congeners, sometimes referred to as co-planar PCBs or dioxin-like PCBs, are considered to have toxicities similar to the most toxic of the PCDDs and PCDFs. EPA has not yet determined how a potentially higher toxicity of these PCBs would impact regulatory findings used to make risk based decisions. It is possible that EPA would find that some risks, which were found to be reasonable using older PCB toxicity information, would be unreasonable when using potentially higher toxicity information. If this is the case, that information my affect any proposed rule that EPA might issue. Any proposed or final PCB rulemaking which relies on the contribution of dioxin-like PCBs to the overall toxicity of PCBs will be based on the finalized Dioxin Reassessment or another EPA peer-reviewed document.

F. Risks of PCB Substitute Materials

EPA seeks information on the current and likely future substitute materials for PCBs that are currently in use or may be put into service in the future. EPA is particularly interested in the chemical, physical, flammability, and toxicological properties of these materials. This information will be essential to a consideration of the net differences in risks, were these materials to be substituted for PCB equipment currently in use.

G. Updating Information on Releases of PCBs

EPA does not have a current, thorough national assessment of the risks to human health and the environment from PCB releases. Information is fragmentary and much of it is geographically limited. For instance, the Great Lakes program in which EPA participates has published recent estimates of PCB releases, but such estimates are statewide, and similar estimates are not available for all States in the United States (Ref. 25). The New York Academy of Sciences published a study of PCB releases into the waterways feeding into the New York/New Jersey harbor, breaking down the releases by type of source (Ref. 26), but similar studies are not available for most waterways in the country. Releases to the environment exceeding the reportable quantity for PCBs must be reported promptly to the National Response Center. In addition to the information which is available through the National Response Center, EPA seeks any information or data on releases of PCBs, to the environment from all kinds of sources, in order to set the releases that are the subject of the regulations being considered into a larger context. EPA seeks information on the causes of such releases, whether the releases reached the environment or were contained, and any information on human health or environmental consequences.

H. Risks From the Contamination of Food from PCB-Containing Oils

Currently the use and storage for reuse of PCB transformers that pose an exposure risk to food or feed are prohibited (40 CFR 761.30(a)(1)(i)). The use and storage for reuse of large high voltage capacitors and large low voltage capacitors which pose an exposure risk to food or feed are also prohibited (40 CFR 761.30(l)(1)(i)). However, both transformers and capacitors containing:

- < 500 ppm PCBs at any weight or volume; or
- < 1.36 kilograms (kg) or 3 lbs. of dielectric fluid at any PCB concentration, are not included in these prohibitions.

To lessen the likelihood of such food and feed contamination from these sources, EPA is considering broadening the prohibition on the use and storage for reuse of PCBs that pose an exposure risk to food and feed, including PCB articles containing greater than 0.05 liters (or approximately 1.7 fluid ounces) of dielectric fluid. PCB concentrations in food are regulated by the Food and Drug Administration and PCB concentrations in feed are regulated by the United States Department of Agriculture (USDA).

There have been two recent incidents of particular note in Europe of very significant contamination of foods and a subsequent recall of those foods from the international market. Because of the presence of trace amounts of dioxins which are present in most PCBs, these two crises also became dioxin crises. These are discussed as follows.

1. *Belgium*. The "Belgian PCB/dioxin crisis" began in January 1999, when 50 kg of PCBs contaminated with 1 gram (g) of dioxins were accidentally added to a stock of recycled fat used for the production of 500 tons of animal feed in Belgium. Although signs of poultry poisoning were noticed by February 1999, the extent of the contamination was publicly announced only in May 1999, when it appeared that more than 2,500 poultry and pig farms could have been involved. The highest concentrations of PCBs and dioxins and the highest percentage of affected animals were found in poultry.

The Belgian government estimates that the dioxin crisis cost approximately $493 million, with approximately $106 million attributed to the loss in the swine sector (in 1999 1 Euro = 1.06 U.S. dollars). As other European Union (EU) countries were also affected by export bans, the final cost of this incident worldwide will likely be higher (Refs. 27, 28, and 29).

2. *Ireland*. In December 2008, Irish pork products were removed from distribution in commerce. This action was taken by the Food Safety Authority of Ireland after finding levels of PCBs and PCDDs in the food at concentrations in excess of EU health standards for food. Preliminary investigations indicated that a single supplier's feed, which had been contaminated from PCB oil in equipment, had been distributed to farmers broadly throughout the Republic of Ireland and Northern Ireland. All pork products produced in Ireland after September 1, 2008 were removed from sale in early December 2008. Details of the full investigation and the economic impact of the contamination are not yet available (Refs. 30, 31, and 32).

I. Risks in Public Buildings From Fluorescent Light Ballasts

EPA is concerned about the release of high concentrations of PCBs from fluorescent light ballasts, particularly in public buildings, such as schools. There are anecdotal accounts of spills from this source and anecdotal information that PCB fluorescent light ballasts have a lifetime of less than 10 years. One of these spills was a significant release from fluorescent light ballasts, almost 20 years after the publication of the PCB use regulations, at the Standing Rock Indian Reservation, ND.

On February 2, 1998, there were complaints of respiratory problems in the administration buildings at the Standing Rock Indian Reservation in North Dakota. On February 5, 1998, EPA received an urgent telephone call from the Standing Rock Sioux Tribe in North Dakota about possible PCB contamination from leaking fluorescent light ballasts. The light ballasts were located in the elementary school, administration building, high school library, and several Bureau of Indian Affairs (BIA) buildings on the reservation (Refs. 33 and 34). EPA determined that many of the fluorescent light ballasts contained PCBs. A sampling contractor found PCBs above EPA's PCB spill cleanup levels in light fixtures, office equipment and carpeting. BIA hired a contractor to decontaminate all areas where it found detectable levels. The contractor removed light ballasts and disposed of all ballasts and contaminated materials as PCB waste. A high school building where contamination was found was closed from February to June, but reopened for summer school. The cleanup for the 4 buildings at Standing Rock cost BIA more than $500,000 (Ref. 35). The estimated cost for removing the non-leaking ballasts from 60 other buildings in the BIA Great Plains Region (formerly the Aberdeen Area) was $60,000.

J. Environmental Justice Considerations

EPA seeks comments on any disproportionate environmental and public health impacts that PCB use and distribution in commerce for use may have on minority, low-income, tribal, and disadvantaged populations. As explained in Unit III.D., it is noted that ATSDR has concluded that there may be an adverse impact on the health of persons who eat fish contaminated with PCBs. Disadvantaged populations may be more exposed to PCBs in contaminated fish than members of the general population. Some disadvantaged communities, such as Indian tribes, have subsistence lifestyles and rely on fish and mammals that may be caught in PCB contaminated waters and environs, as a primary source of nutrition. Fish in these waters may have been contaminated by both PCB wastes disposed of prior to the use authorizations, as well as releases that have occurred from the currently authorized use, distribution in commerce and disposal of PCBs (Refs. 14, 36, 37, 38, 39, 40, and 41).

In addition, EPA is concerned about the presence of the potential risks to urban environmental justice communities from PCB releases at railroad substations, electrical substations, and electrical equipment storage areas. EPA seeks specific information about the prevalence of spills and other releases, including fires, from the use of PCBs in environmental justice areas. The focus of the information gathering in Unit XIV. is owners and operators of regulated electrical equipment and those using PCBs which are authorized in part 40 CFR part 761. However, EPA also seeks comments from minority, low-income, tribal, and disadvantaged persons and their representatives, who are not direct owners or users of PCBs and PCB equipment.

EPA is also announcing public meetings to discuss the Agency's reassessment of the existing PCB use authorizations at several locations around the country. The dates, locations, and times of the meetings are included in Unit XIII. Any additional meetings will be announced on the PCB website (*http://www.epa.gov/epawaste/hazard/tsd/pcbs/index.htm*) at least 30 days prior to the first meeting date. Please refer to the PCB website or call Christine Zachek at (202) 566–2219 for further details. At these meetings, representatives of minority, low-income, tribal, and disadvantaged populations will be able to provide oral comments on the proposed regulations. These persons will also have the opportunity to provide comments to EPA as part of this ANPRM.

VI. Summary of Possible Regulatory Changes for PCB-Containing Equipment Under Consideration

This unit identifies possible changes to the PCB use regulations that EPA may consider in a future notice of proposed rulemaking. Any future regulatory action to propose these changes will be supported by an analysis of costs and benefits, as is required by TSCA. This analysis will be supported, in part, by the quality of the data submitted as a result of the ANPRM.

A. Options for Initial Phaseout Regulations

A potential phaseout of any PCB use authorizations might be implemented gradually, allowing some use to continue under more restrictions before the end of the use authorization. The Agency may consider a number of regulatory measures, including, but not limited to, the following:

- Require testing of equipment which is stored for reuse or removed from service for any reason, and which is assumed to contain PCBs at concentrations ≥ 50 ppm in accordance with §761.2.
- Require that where such equipment is found to contain PCBs at concentrations ≥ 50 ppm after testing, within 30 days of receiving the test results the owner must either reclassify the equipment to < 50 ppm PCBs or designate it for disposal.
- Eliminate all currently authorized PCB equipment servicing except for reclassification.
- Require marking of all equipment which is known or assumed (in accordance with §761.2) to contain PCBs at ≥ 50 ppm.
- Increase the inspection frequency to a minimum of once every month for non-leaking known or assumed ≥ 500 ppm PCB equipment in use.
- Before the final phaseout date(s), broaden the prohibition on the use of PCBs in transformers that pose an exposure risk to food or feed to include use of PCB-contaminated transformers.
- Broaden the definition of PCB article (this would also require changing other definitions) to include all equipment containing > 0.05 liters (or approximately 1.7 fluid ounces) of dielectric fluid with ≥ 50 ppm PCBs, in place of the current definition which regulates transformers and capacitors containing ≥ 3 lbs. of dielectric fluid.
- Require registration of PCB large capacitors containing a specified volume of dielectric fluid or having a specified external volume or dimensions.
- Eliminate the authorization for storage of PCB equipment for reuse.
- Eliminate the use authorization for PCBs in carbonless copy paper.
- Eliminate totally enclosed determination for distribution in commerce.
- Require reporting/notification to EPA Regional Administrators when PCBs are found in any pipeline system, regardless of the source of PCBs or the owner of the pipeline.

B. Potential Time Frames for Completing the Removal of PCB Equipment From Service

These measures would phaseout all PCB-electrical equipment uses with interim deadlines by equipment concentration and type.

- By 2015, eliminate all use of askarel equipment (≥ 100,000 ppm PCBs), removing from service the equipment in high potential exposure areas first. EPA is considering allowing exceptions on a case-by-case basis based on hardship and no unreasonable risk. Exceptions may be granted based on an application and approved exceptions may be published on the PCB website.
- By 2020, eliminate all use of oil-filled PCB equipment (≥ 500 ppm) and the authorization for use of PCBs at ≥ 50 ppm in pipeline systems.
- By 2025, eliminate all use of any PCB contaminated equipment (≥ 50 ppm), which is still authorized for use.

VII. Information to Be Considered During EPA Reassessment of PCB Use Authorizations

This unit outlines what information EPA believes is important to consider when reassessing PCB use authorizations. EPA seeks comment on any other information, which may not be included in this unit, but which you believe is important for EPA to consider when reassessing PCB use authorizations.

A. Liquid-filled Electrical Equipment (Except Railroad Transformers and Mining Equipment)

EPA seeks information on the specific population of any electrical equipment that contains greater than 2 fluid ounces of dielectric fluid with PCBs ≥ 1 ppm and that was manufactured prior to July 31, 1979: Transformers (regulated at 40 CFR 761.30(a)), electromagnets (regulated at 40 CFR 761.30(a)), switches (regulated at 40 CFR 761.30(h)), voltage regulators (regulated at 40 CFR 761.30(h)), electrical capacitors (regulated at 40 CFR 761.30(l)), circuit breakers (regulated at 40 CFR 761.30(m)), reclosers (regulated at 40 CFR 761.30(m)), liquid-filled cable (regulated at 40 CFR 761.30(m)), and rectifiers (regulated at 40 CFR 761.30(r)). Each unit describes specifically what information EPA solicits. EPA encourages small business owners and small municipal and cooperative utilities to provide details on their PCB-containing electrical equipment population characteristics and their management activities for the equipment.

1. *Population characteristics for transformers, electromagnets, switches, voltage regulators, electrical capacitors, circuit breakers, reclosers, liquid-filled cable, and rectifiers.* Information that EPA seeks about the use of this equipment appears in questions, which are located in Unit XIV.A.–E.

2. *Servicing.* Since the first use regulations for liquid-filled PCB-containing equipment, EPA has continued to prescribe conditions for authorized servicing (maintaining or repairing) this equipment, which facilitated extending the life of the equipment, in order to ease the hardship an immediate ban would have caused owners. Most life-extending use conditions are included in the authorization for servicing:

- Draining, repairing, and putting back into service PCB-contaminated electrical equipment.
- Topping off and putting back into service PCB-electrical equipment.
- Blending the oil drained from multiple pieces of PCB-containing equipment for servicing.
- Adding blended or other PCB-containing oil into repaired, drained equipment.
- Reclassifying.
- Distributing PCB-containing equipment in commerce for repair without manifesting.
- Storing company-owned equipment for servicing without any conditions to protect against leaks or spills.

• Servicing equipment which is owned by others, without having commercial storage approvals.

EPA believes that this equipment is nearing the final stages of useful life, after a minimum of 30 years of use. When this aging equipment fails to function in use or is otherwise removed from service, and if there is a need to prolong the life of the equipment, EPA believes that the PCBs should be removed from the equipment and disposed of in accordance with the regulations in 40 CFR part 761, subpart D. The reclassification of out-of-service equipment could be considered preventive maintenance and does not require service interruption, lost revenue, or liability costs of losses to other parties. In the brochure, entitled "Promoting the Voluntary Phase-Down of PCB-Containing Equipment," published in October 2005 by the Utilities Solid Waste Activities Group (USWAG) (Ref. 42), it states that:

> Many utility companies across the country have procedures in place to ensure that most equipment containing PCBs in concentrations > 50 ppm identified after removal from the field is either disposed of and not returned to service or retrofilled before being returned to service. This practice helps ensure the accelerated retirement from service of a large class of potentially PCB-containing equipment (e.g., distribution pole-top and padmount transformers) that could otherwise lawfully be placed back into service. USWAG will continue to actively promote these systematic practices of voluntarily identifying and retiring PCB-containing equipment from service.

On April 2, 2001, EPA provided new reclassification procedures which include refilling mineral oil filled equipment with liquid containing < 2 ppm total PCBs (Ref. 10). A majority of liquid-filled equipment which was manufactured to contain mineral oil dielectric fluid (mineral oil) and which remains in use can be easily reclassified to contain < 50 ppm with a thorough draining and refilling with liquid containing < 2 ppm PCBs. If an owner determines that the equipment is not worth reclassifying, there currently are numerous disposal options and excess disposal capacity for the equipment. EPA seeks information on the types and extent of service-extending maintenance and rebuilding of PCB-containing transformers, railroad transformers, heat transfer systems, hydraulic systems, electromagnets, switches, voltage regulators, circuit breakers, reclosers, cable, and rectifiers. EPA's questions about servicing are located in Unit XIV.F.

3. *Identifying and managing the use, removal from use, and disposal.* In the public comments provided during the 1979 rulemaking, electrical equipment owners stated that they did not know where PCB-containing equipment was located (Ref. 3). In the 30 years since, EPA believes that it would have been prudent for owners to implement a plan during that time to locate any regulated equipment. The common use and availability of bar code labels and scanning equipment and user-friendly computerized inventory management systems, plus the ability of global positioning systems to precisely specify locations, should facilitate the development and maintenance of an inventory of PCB-containing regulated equipment. Equipment owners previously told EPA that it was not possible to determine whether mineral oil-filled equipment contained PCBs unless the oil was tested, and testing was expensive. EPA agrees that it is necessary to collect oil to test it and there is a cost associated with the oil sample collection and chemical analysis. However, at the time of disposal it is already necessary to test to determine the PCB concentration to determine how the equipment is regulated for disposal. Based on current regulatory requirements, the cost of chemical analysis would have to be paid at the time of the disposal of the equipment, regardless of a non-attrition-based phaseout. Collection and analysis of oil would only be an additional cost if EPA imposes a new requirement to test in-service and energized equipment.

Currently there are several options available for equipment that is no longer operable, or is otherwise designated for disposal. For equipment with recyclable metals, some disposal companies are paying for this equipment, because they can recover their costs and make a profit, even when paying the waste generator for "scrap metal." In 2001, EPA facilitated the reclassification of electrical equipment making this a cost effective means of removing the risk from PCBs in equipment, while continuing to use the equipment until it no longer functions or is voluntarily removed from service for disposal (Ref. 10).

In 1996, EPA surveyed the PCB disposal industry and found that there was a large capacity surplus (Ref. 35). However, as the PCB disposal market increasingly becomes smaller, it may be that fewer disposers will find it economical to retain licenses and disposal facilities for this small market, decreasing the number of options available and very likely increasing the costs for the remaining options. Any increased cost of fuel employed in many disposal technologies and for the transportation of equipment to disposers will likely also increase disposal costs in the future. The potential increase in disposal costs in the future may make it economically advantageous to either reclassify equipment or dispose of it now, even if it has not reached the end of its useful life.

Owners commented in 1979 that there were few commercial storers for PCB wastes (Ref. 3). Currently, EPA believes that there is an excess of storage capacity. Like disposal, commercial storage capacity could also decrease as the supply of PCB equipment diminishes. EPA seeks information on whether advancing the date of testing from some future disposal date to a date closer to the present time would present cost, economic, or management difficulties or advantages to the owners and operators of PCB-containing equipment.

4. *Information about an increased failure rate of vintage electrical equipment.* A 2002 report, Life Cycle Management of Utility Transformer Assets, by the Hartford Steam Boiler Inspection and Insurance Company, uses information from claims filed by policy holders with the insurer for failed transformers, regardless of whether they contained PCBs (Ref. 23). The information has been used to estimate or predict when equipment will fail, based on historical failures for which claims were filed. This document also highlights that the electricity demand load grew 35% and the transmission capacity grew 18% over the 10 preceding years. EPA is concerned that the rate of failures for transformers manufactured in the 1950s, 1960s, and 1970s may increase substantially in the future. EPA seeks data on the failure rate in the last 10 years and the results and documentation of recent modeling of projections of failures into the future. EPA seeks information on any differences in failure rate for different types of equipment of different vintages, and differences in failure rates for equipment which is located indoors as compared to outdoors and what effect, if any, that electronic monitoring and other maintenance methods have had on failure rates. EPA's questions about failure rates are located in Unit XIV.G.

5. *Severe weather event and other natural disasters increase the potential risk from PCBs.* There have been recent severe weather events (e.g., Hurricane Katrina (Ref. 44), Tornado in Greensburg, KS (Ref. 45)) where there was significant damage to electrical equipment of all ages, both containing PCBs and not containing PCBs. Although there have not been reports of

natural disasters such as earthquakes, mudslides, or volcanic eruptions which resulted in significant spills of PCBs, there is a possibility that this could have occurred in some regions of the country. These unpreventable events contribute to catastrophically ending the useful life of PCB-containing equipment and the uncontrolled release of PCBs. EPA believes that one cost-effective protection against PCB releases from these weather events and natural disasters may be a proactive program to test equipment that is taken out of service for PCBs, and to remove, test, and replace or retrofill equipment in service that is known or assumed to contain PCBs, especially the equipment in locations and areas where a release would present the greatest risk. EPA is also concerned about areas which may not be directly contaminated from nearby equipment ravaged by severe weather, but where spilled PCBs from that weather event might be expected to migrate and accumulate, such as spillways and drinking water reservoirs. Answers to the questions about severe weather events in Unit XIV.H. and other related comments will assist EPA in the reassessment of the use of PCB-containing electrical equipment.

6. *Alternatives to PCB liquids*. One type of information the Agency is soliciting for its proposed rulemaking relates to alternatives to the use of PCBs in liquid-filled equipment. To EPA's knowledge, satisfactory substitutes are available to replace PCBs in all electrical equipment applications. The Agency welcomes comments on the comparative costs and the effectiveness of various substitutes in reducing fires and heat-related degradation or destruction of equipment. EPA seeks information on the hazards and the risks posed by these PCB substitutes. EPA's questions about alternatives to PCB liquids are located in Unit XIV.I.

7. *Removal and replacement costs*. EPA seeks information on the costs of removing and replacing old PCB-containing equipment with new or used non-PCB equipment based on attrition (i.e., end of equipment's useful life) and based on removal in advance of attrition. In particular, EPA would like to have information on:

- How often any equipment (PCB-containing or non-PCB–containing) of the same age or size is replaced per year and the costs for replacement.
- Costs for replacement include cheapest source, foreign, or domestic, including transport and transaction costs.
- The price for replacement of various types and classes of equipment each year over the last 30 years, as well as estimated or projected future prices.

EPA seeks information that explains:

- The impact of changes in system distribution and transmission voltage on the potential obsolescence of mineral oil-filled equipment, which was manufactured before 1979 would be useful.
- The cost impact of replacing mineral oil-filled equipment, which was manufactured before 1979, with more modern equipment with respect to efficiency, longevity, or any other attribute which would create an economic incentive to hasten the phaseout of older equipment.

Further, EPA solicits information on the numbers of these units manufactured before 1979 that are:

- Expected to be replaced or excessed during system voltage changes.
- Planned for distribution in commerce for use. EPA would also like to know to whom these excessed units would most likely be sold.

EPA seeks information on the costs of service interruptions and revenue loss which may result from equipment replacement, either scheduled or unplanned. Similarly, EPA solicits comments on the current and estimated future supply of replacement equipment, when PCB–containing equipment is moved out of service before the end of its useful life. Reclassification options and procedures in the regulations were broadened in 2001 (Ref. 10) and EPA seeks comments on the costs and advantages found for this option, as opposed to disposal. EPA encourages small business owners, and small municipal and cooperative utilities to provide details on their PCB-containing electrical equipment replacement schedules and costs. EPA's questions about PCB equipment removal and replacement costs are located in Unit XIV.J.

8. *Current PCB waste disposal capacity*. EPA solicits comments on the availability of disposal capacity for PCBs in liquids at concentrations ≥ 50 ppm by weight, and for other materials in drained electrical equipment. EPA also seeks comments on the economic benefits of decontamination and recycling of liquids or non-liquids in this equipment, where possible. In 1979, PCB disposal options and capacity were limited and the potential demand on disposal capacity from a ban or phaseout of PCB-containing equipment would have been high. EPA also seeks information on whether there currently is a charge to the equipment owner (waste generator) for disposing of equipment which will be decontaminated and then sold as scrap metal. EPA also seeks information on the cost for disposing of mineral oil contaminated with PCBs. EPA has seen a continuous decrease in the numbers of PCB disposal approvals issued over the last 10 years. EPA seeks comment on what the disposal industry predicts with respect to the future number of approved PCB disposal and storage companies, future disposal and storage capacity, and the future cost of commercial storage and disposal of electrical equipment waste as compared to current disposal costs. EPA's questions about PCB waste disposal capacity are located in Unit XIV.K.

9. *Current equipment management practices*. EPA solicits information on the current management practices intended to reduce the risk from PCBs in the following types of equipment that contain PCBs at concentrations of ≥ 1 ppm: Electrical transformers, railroad transformers, mining equipment, electromagnets, switches, voltage regulators, electrical capacitors, circuit breakers, reclosers, liquid-filled cable, and rectifiers. EPA encourages small business owners, small municipal and cooperative utilities to provide details on their PCB-containing electrical equipment management activities. EPA's questions addressing the information that EPA seeks about equipment current management practices are located in Unit XIV.L.

10. *Electrical equipment which contains non-liquid PCBs at concentrations ≥ 1 ppm*. EPA seeks information on electrical equipment, such as tar-filled equipment, which was manufactured prior to July 31, 1979, in the following categories: Containing non-liquid PCBs at concentrations ≥ 1 ppm and < 50 ppm, ≥ 50 ppm and < 500 ppm, ≥ 500 ppm and < 100,000 ppm, and ≥ 100,000 ppm. EPA seeks this information for the following non-liquid filled equipment types: Transformers, electromagnets, switches, voltage regulators, electrical capacitors, circuit breakers, reclosers, rectifiers, and any other equipment populations (such as paper insulated lead cable and bushings). EPA's questions about electrical equipment which contains non-liquid PCBs at concentrations ≥ 1 ppm are located in Unit XIV.M.

11. *Impact of vandalism and theft on the risk from PCBs*. The presence of PCBs in equipment subject to vandalism incidents could increase potential risk not only to the vandal, but to others in the area. In particular, EPA is concerned about areas which may not be directly contaminated from the nearby equipment impacted by vandalism but also areas where spilled PCBs from that

vandalism might be expected to migrate and accumulate such as low-lying residential neighborhoods and cropland. EPA solicits data on the number of units lost and the cost from losses from vandalism and theft of electrical transformers, railroad transformers, mining equipment, heat transfer systems, hydraulic systems, electromagnets, switches, voltage regulators, electrical capacitors, circuit breakers, reclosers, liquid-filled cable, and rectifiers. EPA seeks information on the rate of occurrence of vandalism events involving PCB-containing equipment in each calendar year starting from 1998 until 2008, including how many gallons of oil have been lost from equipment and what has been the cost from this loss of oil. EPA's questions about the impact of vandalism and theft on the risk from PCBs are located in Unit XIV.N.

12. *Fraudulent export for scrap metal recovery*. EPA is concerned about the potential for incidents where used electrical equipment is exported for purported reuse, but where the equipment is actually scrapped or smelted for recovery of metal components. Elimination of the totally enclosed determination for distribution in commerce will restrict the fraudulent practice of export of equipment in the guise of reuse, when the exported equipment will not be used, properly reclassified/decontaminated, or disposed of in an environmentally sound manner. EPA is concerned that metal recycling facilities may not manage the exported equipment and the PCBs in an environmentally sound manner; and scrap metal management workers may not be protected from exposure to PCBs or even know that PCBs are present in the exported equipment.

13. *Reclassification of askarel transformers*. EPA is concerned that reclassification of askarel transformers (which were manufactured to contain ≥ 500,000 ppm PCBs) is generally ineffective because PCBs leach back out of internal components several years after the active processing to reclassify is completed. This seems plausible because of the nature of the inner structure of transformers. EPA is considering whether to restrict the reclassification option to electrical equipment which at the time of manufacture contains < 10,000 ppm (< 1%) PCBs, based on the inability to drain and flush PCBs efficiently from askarel PCB equipment. EPA's questions about the reclassification of askarel transformers are located in Unit XIV.O.

14. *Registration of PCB large capacitors*. PCBs were formulated at concentrations from about 75 weight percent to about 100 weight percent (or 750,000 ppm to 1,000,000 ppm) in capacitors (Ref. 46). Therefore, the amount of PCBs in the smallest PCB large capacitor, which contains 1.36 kg or 3 lbs. of dielectric fluid, is about 1.02 kg. (or about 2.25 lbs.). There could be as much PCBs of the same PCB formulation in the smallest PCB large capacitor as the approximately the same amount of PCBs in a transformer which contains 600 gallons of 500 ppm PCBs in mineral oil dielectric fluid. The regulations currently require that a mineral oil transformer containing 600 gallons of 500 ppm PCBs and even a much smaller 1–gallon transformer containing 500 ppm of PCBs in mineral oil dielectric fluid to be registered with EPA. In order to protect first responders and others who might potentially be accidentally exposed to PCBs from PCB large capacitors, EPA is assessing whether to require registration of some or all PCB capacitors currently in use with EPA. EPA could publish and post the register of the capacitors on the PCB website as it has the Transformer Registration Database.

B. Railroad Transformers (Regulated at 40 CFR 761.30(b))

At the time of the 1979 rulemaking there were a limited number of PCB transformers used on electric railroad engines and cars. The railroads where the askarel PCB equipment was used were located in the northeastern part of the country, mainly in Pennsylvania, New Jersey, and New York (Ref. 47). Because of the known leakage from this equipment and the requirement for frequent servicing, EPA found that the distribution in commerce of this equipment was not totally enclosed. The leaks from the use of this equipment have resulted in Superfund PCB cleanups of some Southeastern Pennsylvania Transportation Authority (SEPTA) track areas. EPA assumes that by now, all of the PCB railroad transformers have either been removed from service or the dielectric fluid has been replaced and that all railway transformers are now operating with dielectric fluid which contains < 50 ppm PCBs. EPA seeks comments on the continued use of PCBs in railroad transformers, and is considering eliminating the authorization for the use of PCBs in railroad transformers at concentrations greater than 1 ppm. EPA's questions about the railroad transformers are located in Unit XIV.P.

C. Mining Equipment (Regulated at 40 CFR 761.30(c))

In 1978, there were only very limited uses of PCBs in electric motors in fewer than 1,000 mining machines (Ref. 2). The motors were manufactured in the 1960s and early 1970s by one company and used in machinery manufactured by another company. The PCBs were used as a motor coolant. Because of its operating conditions, this equipment must frequently be rebuilt. Based on the small usage in 1979 and the expected relative short life of this limited use population, EPA believes it is likely that PCBs are no longer used in the motors of mining equipment. EPA seeks comments on whether there is any continued use of PCBs in such electric motors in mining equipment and whether EPA should eliminate the authorization for the use of PCBs in mining equipment at concentrations > 1 ppm. EPA's questions about mining equipment are located in Unit XIV.Q.

D. Heat Transfer Systems (Regulated at 40 CFR 761.30(d)) and Hydraulic Systems (Regulated at 40 CFR 761.30(e))

Heat transfer systems and hydraulic systems have been authorized for use since 1984, when they contain PCBs at concentrations < 50 ppm. Because of the common leakage from this equipment and the frequent requirement for servicing, the distribution in commerce of this equipment was not found to be totally enclosed. The regulatory provisions for this equipment at 40 CFR 761.30(d) and (e) have been in place for almost 25 years. EPA seeks information on the number of these units, their types, and how frequently draining and refilling takes place. Because these types of equipment are often serviced by draining and refilling with new PCB-free fluid, EPA believes it is likely that any residual PCBs present in equipment that was in use in 1984, has been diluted through servicing to a concentration far below 50 ppm. There may be no reason to continue an authorization of PCBs in equipment at measurable concentrations. EPA seeks information demonstrating a need to continue to use PCBs in heat transfer systems and hydraulic systems at concentrations greater than 1 ppm.

E. Carbonless Copy Paper (Regulated at 40 CFR 761.30(f))

In 1979, there were many files containing carbonless copy paper. EPA does not have information on whether the information on this 30–year old, thin carbon copy paper is still legible, and if it is not legible, why it cannot be disposed of. Thirty years later it may be feasible and economical to convert any necessary, legible information and records from carbonless copy paper to a different storage medium. EPA seeks information on the volume of records on carbonless copy paper, the records' locations, and the types of business, government agencies, or other holders of such documents. EPA would like to know whether holders of such documents are smaller or larger businesses, and whether the size or type of the business would affect the economic feasibility of document conversion. EPA seeks comments on whether carbonless copy paper containing PCBs is still in use and whether there is a need to continue the existing use authorization for this paper.

F. Continued Use of Porous Surfaces Contaminated with PCBs Regulated for Disposal by Spills of Liquid PCBs (Regulated at 40 CFR 761.30(p))

EPA is considering changing 40 CFR 761.30(p) to reflect the continued potential risk from contaminated porous surfaces. Persons who are potentially exposed to contaminated porous surfaces should be protected from air emissions, which are not eliminated under the existing use authorizations by encapsulation or metal covers. EPA's questions about the use of contaminated porous surfaces are located in Unit XIV.R.

G. Use in Fluid and Gas Transmission and Distribution Systems (Regulated at 40 CFR 761.30(i), 40 CFR 761.30(s), and 40 CFR 761.30(t))

In comments on the June 7, 1978, proposed rule (Ref. 5), which was finalized in 1979, two natural gas transmission companies claimed that they had PCBs in turbine compressors at concentrations ≥ 50 ppm, but they could not reduce these concentrations to levels < 50 ppm in the near future. One company claimed to have removed all of the PCB turbine oil in 1972. The companies claimed that the PCBs would not leak out of the compressors into other parts of the natural gas pipeline system. In the May 31, 1979 final rule (Ref. 3), EPA prohibited the use of PCBs at concentrations > 50 ppm in natural gas pipeline systems, effective as of May 1, 1980.

In the early 1980s, PCBs were found in a cold trap in the gas line outside a home in New York. In 1981, EPA entered into agreements with 13 natural gas transmission companies which had PCBs at concentrations ≥ 50 ppm in their systems but outside of turbine compressors (Ref. 48).

It is not clear exactly how the PCBs entered the systems if they did not come from the turbine compressors. After nearly 30 years of operations and after all known sources of PCBs were removed from these systems, EPA has information indicating that PCBs at levels ≥ 50 ppm continue to be found in natural gas pipeline systems including within equipment which is not specifically designed to collect such material. EPA believes that the authorized use conditions in the current regulations should have resulted in companies removing PCBs to the extent that there no longer are PCBs in the systems at concentrations ≥ 50 ppm.

EPA is considering requiring sampling and analyzing individual condensate samples (not composites or accumulations) to determine the extent of the PCB contamination when any person finds PCBs in any pipeline system at concentrations ≥ 1 ppm. Owners would be required to analyze condensate from surrounding areas to confirm that regulated PCBs were not present in the system. Regardless of the original or current source of the PCBs, owners would report results of ≥ 50 ppm findings to EPA. EPA is also considering whether to propose ending the use authorization for PCBs at concentrations ≥ 1 ppm in these systems by 2020 or an earlier date. In this phase-down approach, owners would also be required to analyze current condensate in areas having historical PCB measurements to confirm the absence of PCBs during the period prior to the final phaseout date. If PCBs are found, owners would have to demonstrate they have reduced PCB concentrations to < 1 ppm or have implemented engineering controls similar to the current requirements in 40 CFR 761.30(i)(1)(iii)(A)(*4*) to reduce and prevent migration of PCB impacted material. EPA seeks comments on the continued use of PCBs in fluid and gas transmission and distribution systems. EPA's questions about use in gas transmission and distribution systems are located in Unit XIV.S.

EPA has little information on the need to continue the use authorizations at 40 CFR 761.30(s) for air compressor systems and 40 CFR 761.30(t) for other gas or liquid transmission systems. The 10 years that these authorizations have been in place should have allowed owners sufficient time to purge the PCBs from their systems. EPA is considering whether to terminate or significantly limit the duration of these authorizations.

H. Use in Research and Development (Regulated at 40 CFR 761.30(j), Scientific Instruments (Regulated at 40 CFR 761.30(k)), and Decontaminated Materials (Regulated at 40 CFR 761.30(u))

EPA is not currently planning to reassess the authorizations for: Use in research and development, scientific instruments, and decontaminated materials. However, EPA welcomes comments on these use authorizations.

I. No Use Authorization for PCB-Containing Electrical Equipment Parts

There is no use authorization for parts or detached ancillary equipment, such as bushings, for electrical equipment when separate from that equipment. Bushings contain insulating material separated from the primary equipment's insulating fluid. Bushings may be removed from equipment during servicing or transportation. Utilities have told EPA that it is necessary to store bushings for reuse, especially for large transmission electrical equipment. There is no use authorization in 40 CFR part 761, subpart B, for bushings, which are no longer attached to or associated with a specific article of authorized equipment (Ref. 10). EPA seeks information on the feasibility of reclassifying bushings or other ancillary equipment, which can be used as spare parts. EPA seeks information on the economic value of continuing to maintain such PCB-containing parts and ancillary equipment in inventories of utility companies and industrial facilities. EPA's questions about the use of PCB-containing electrical equipment parts are located in Unit XIV.Y.

J. Reassessment of the Possible Authorization of the Use of Some Non-Liquid PCB-Containing Products

The use of PCBs at concentrations of 50 ppm or greater in caulk products, regardless of whether the PCBs were created by an inadvertent chemical reaction during the manufacturing process or were added to the caulk afterward, is not currently authorized under TSCA section 6. EPA requests comments on whether the use of PCBs in caulk should be authorized, and what data or other information is available on which to evaluate the risks and benefits of the use of PCB-containing caulk. EPA's questions about authorization of some non-liquid PCB-containing products are located in Unit XIV.Z.

VIII. Storage for Reuse of PCB Articles (Regulated at 40 CFR 761.35)

EPA established limits on storage of PCB articles for reuse at 40 CFR 761.35. These limits were established to curtail storage practices which were not in keeping with the statutory objectives of:

1. A general ban on use with limited exceptions.

2. Quick disposal of PCB-containing equipment which was no longer used or usable.

3. Protection of human health and the environment from risks presented by PCBs.

When the PCB regulations were first promulgated in the late 1970's, EPA recognized that it might be necessary to have PCB-containing spare equipment to press into use when other new or reasonably new equipment needed to be replaced. However, nearly 30 years later, the demand for PCB-containing equipment replacements should be much lower. EPA has information indicating that the older unused PCB equipment, now 30 years old or older, does emit PCBs even when sealed and still can leak even when it is not energized. EPA also seeks information about whether stored non-askarel equipment could be reclassified while it is in storage for reuse. EPA also is concerned that equipment, which is stored for reuse outside of a secure storage facility, is more susceptible to potential releases of PCBs to the environment from accidents, both weather-related and the result of the owner's activities, and to vandalism or theft.

EPA seeks information on the location of equipment being stored for reuse, especially in relationship to the equipment it is to replace. EPA seeks information on the economic value of continuing to maintain PCB-containing equipment which is not in use, in inventories of utility companies and industrial facilities. EPA's questions about storage for reuse of PCB articles are located in Unit XIV.T.

IX. Distribution in Commerce of Electrical Equipment (Regulated at 40 CFR 761.20)

PCBs have been measured in the ambient air coming from PCB-containing equipment in storage for disposal in an approved PCB storage facility. Information about the measurement of PCBs in the ambient environment around stored electrical equipment indicates that aging equipment appears to no longer be airtight, even if seemingly "intact and non-leaking" upon cursory visual inspection (Ref. 11). If this stored equipment is not airtight, there must also be releases during use and transportation (distribution in commerce) of this equipment, despite its deenergized state. EPA is also concerned about and seeks information on the frequency of PCB surface contamination on this equipment and the practice of routine inspection for the presence of residual PCB surface contamination on equipment, by using a standard wipe test. For this reason, EPA questions whether the historical determination that distribution in commerce of PCBs in electrical equipment still can be considered totally enclosed in accordance with TSCA section 6(e)(2)(C). Elimination of distribution in commerce of this PCB-containing equipment for reuse could also prevent the fraudulent practice of a guise of resale for reuse. One fraudulent practice is a claim of the export of regulated PCB-containing equipment for reuse to avoid proper domestic reclassification or disposal, when the equipment is intended only for foreign scrap metal recovery. EPA's questions about distribution in commerce are located in Unit XIV.U.

X. Reconsideration of the Use of the 50 ppm Level for Excluded PCB Products, in Particular for PCBs in Caulk

The level of 50 ppm has been used in PCB use regulations since 1979. Based on regulatory history, this number is based almost entirely on economic considerations. There are no traditional exposure and risk assessment calculations (Refs. 3 and 8). EPA seeks comments on the application of the value of 50 ppm as the upper value in the definition of Excluded PCB products in 40 CFR 761.3. One such excluded product is PCBs in caulk where PCBs are present at concentrations < 50 ppm. EPA is seeking comment and any supporting data or other information on whether the number 50 ppm should be changed given the recent realization that the use of PCBs in caulk may be widespread and may be an undue burden for schools if the exclusion continues at 50 ppm. EPA's questions about excluded PCB products are located in Unit XIV.X.

XI. Definitional Changes Under Consideration (Located at 40 CFR 761.3)

EPA is considering proposing changes to the following definitions found at §761.3, and solicits comments on these changes.

A. PCB Articles

The definition of PCB articles in §761.3 includes transformers and capacitors, but it has no mention of size or the volume of liquid contained in the article. EPA is considering changing this definition to regulate equipment containing ≥ 0.05 liters (approximately 1.7 fluid ounces) of dielectric fluid. Definitions for Capacitor, PCB Capacitor, PCB Transformer, and PCB-contaminated Electrical Equipment would be adjusted accordingly. This revision would correspond to minimum volumes for liquid-filled equipment found in the Stockholm Convention.

EPA seeks information on the type and volume of PCB products that would be affected by such changes in the definition, as well as the cost, economic, and other impacts of these changes.

B. Excluded Manufacturing Process

The current definition states, "The concentration of inadvertently generated PCBs in products leaving any manufacturing site or imported into the United States must have an annual average of less than 25 ppm, with a 50 ppm maximum." EPA is considering whether to eliminate the annual average and whether the maximum concentration should be set at < 1 ppm. EPA's questions about excluded manufacturing processes are located in Unit XIV.V.

C. Recycled PCBs

The current definition states, "The concentration of PCBs in paper products leaving any manufacturing site processing paper products or paper products imported into the United States must have an annual average of less than 25 ppm, with a 50 ppm maximum." EPA is considering whether to revise the annual average and whether the maximum should be lowered. Additionally, the definition requires the release of PCBs to ambient air at any point be at concentrations < 10 ppm. EPA is considering whether the maximum allowable PCB concentration released to air should be lowered to be consistent with what the Agency has said about PCB exposures from PCBs in caulk (Ref. 49). EPA's questions about recycled PCBs are located in Unit XIV.W.

D. Quantifiable Level/Level of Detection

In the years since this definition was first promulgated, analytical measurement technology has improved so that the current quantitation level/level of detection is lower. Currently, the quantitation level in mineral oil can be as low as, or lower than, 1 ppm and the level of detection can be as low as, or lower than, 0.5 ppm. The quantitation level and level of detection in other media such as air and water can be three orders of magnitude or more lower than the values for mineral oil. EPA is evaluating whether to change this definition to reflect to most current science, and solicits any information regarding such a change.

XII. Marking of All PCB Articles

EPA is considering requiring marking of all PCB articles, which includes electrical equipment containing ≥ 50 ppm PCBs, and all storage areas. Some ≥ 50 ppm PCBs items are already required to be marked in 40 CFR 761.40:

- Above-ground sources of PCB liquids in natural gas pipeline systems.
- PCB containers.
- Electric motors using PCB coolants.
- Hydraulic systems using PCB hydraulic fluid.
- PCB heat transfer systems.
- PCB article containers.
- Areas used to store PCBs and PCB items for disposal.
- Transportation vehicles transporting more than 45 kg or 99.5 lbs of items containing ≥ 50 ppm liquids, containers of ≥ 50 ppm liquids, or one (or more) PCB transformers.

EPA discussed concerns about PCB releases from liquid-filled equipment, regardless of concentration, during natural disasters in Unit VII.A.5. The consequences of natural disasters and other events such as automobile collisions with equipment and vandalism (e.g., shots from firearms), may be more significant when damaging older and over-loaded electrical equipment. In addition to those persons who might be accidentally exposed, it is important that public emergency responders as well as owners/maintainers be advised of the PCB content of PCBs in use or those catastrophically released from use as quickly as possible. In addition, residents and the public in proximity to regulated equipment have the right to know of the presence of PCBs. Many owners already know the locations of and have already marked PCB-contaminated equipment. EPA believes that marking of PCB-contaminated equipment also aids in planning management of equipment during transportation and storage for disposal. A possible requirement under consideration is for owners to locate and label PCB-contaminated equipment. This would require an owner to take additional labeling action beyond what is required in the current regulations for the use of PCB-contaminated equipment and the assumptions in 40 CFR 761.2. Once equipment was marked for use, it would not need to be re-marked at the time of disposal. In Unit XIV.A.–E., M., P., Q., and S. EPA has asked for specific numbers of PCB-contaminated equipment and the size of populations of equipment which is assumed by regulation to contain PCBs ≥ 50 ppm.

XIII. Public Participation

In addition to the requests for information and comments contained in this document, EPA intends to involve stakeholders through a series of public meetings taking place in locations across the country. The purpose of these meetings is to receive stakeholder comments on the issue of EPA's reassessment of PCB use authorizations, including the questions described in Unit XIV.

A. Meeting Dates and Locations

The meetings will be held as follows:

1. New York, NY, May 4, 2010, from 1 p.m. to 5 p.m. at EPA Region 2 offices, Room 2735, Conference Room A (27th Floor), 290 Broadway.
2. Chicago, IL, May 18, 2010, from 1 p.m. to 5 p.m., at the EPA Region 5 offices, Lake Michigan Room (12th Floor), 77 West Jackson Blvd.
3. Atlanta, GA, May 25, 2010, from 1 p.m. to 5 p.m., at EPA Region 4 offices, Rooms 9D and 9E, Sam Nunn Atlanta Federal Center, 61 Forsyth St., SW.
4. Washington, DC, May 27, 2010, from 1 p.m. to 5 p.m., at EPA Headquarters, EPA East, Room 1153, 1201 Constitution Ave., NW.

B. Meeting Procedures

For additional information on the scheduled meetings, please see the PCB website (*http://www.epa.gov/epawaste/hazard/tsd/pcbs/index.htm*) or contact Christine Zachek at (202) 566–2219 or *zachek.christine@epa.gov*.

The meetings will be open to the public. To ensure that all interested parties will have an opportunity to comment in the allotted time, oral presentations or statements will be limited to 10 minutes. EPA therefore recommends that stakeholders who present oral comments also submit written comments following the instructions provided under **ADDRESSES**. Interested parties are encouraged to contact the technical person at least 10 days prior to the meeting to schedule presentations. Since seating for outside observers will be limited, those wishing to attend the meetings as observers are also encouraged to contact the technical person at the earliest possible date, but no later than 10 days before the meetings, to ensure adequate seating arrangements.

To request accommodation of a disability, please contact Christine Zachek at (202) 566–2219 or *zachek.christine@epa.gov*, preferably at least 10 days prior to the meeting, to give EPA as much time as possible to process your request.

XIV. Request for Comment and Additional Information

EPA invites public comment and any additional information in response to the questions identified in Unit XIV.A through Unit XIV.AA. Unit I.B. contains a description of points commenters should consider when preparing comments for submission to EPA, including how to submit any comments that contain CBI. No one is obliged to respond to these questions, and anyone may submit any information and/or comments in response to this request, whether or not it responds to every question in this unit.

A. Populations of Transformers (Containing Greater Than 2 Fluid Ounces of Dielectric Fluid)

1. What percentage of your entire transformer inventory in use or storage for reuse was manufactured each year between 1950 and 1980, all years up to 1949, and all years from 1981 to date? If this information is not available, please provide alternative information, such as: What percentage of the entire transformer inventory is 30 years old, 40 years old, and 50 years old?
2. Of the inventory information provided in the previous question, how does the percentage differ for the following applications: Transmission, substation, pole top, and pad mount?
3. What percentage of your transformer population consists of PCB transformers? How many units are in this population? How does the percentage and population compare for major interstate utilities, municipal utilities, cooperative utilities, industrial owners, and other groups?
4. What percentage of your transformer population consists of PCB-contaminated transformers? How many units are in this population? How does the percentage and population compare for major interstate utilities, municipal cooperatives, industrial owners, and other groups?
5. For electrical utilities and other owners, have you tested all potentially (based on year of manufacture and other information) contaminated equipment? Do you know where all regulated PCB equipment is currently located? Have you removed all askarel containing PCB transformers? Have you removed all mineral oil containing PCB transformers? Have you removed all mineral oil containing PCB-contaminated transformers?
6. What percentage of the transformer population consists of transformers which contain measurable PCBs between 1 and 50 ppm and were manufactured before July 31, 1979? How

many units are in this population? How does the percentage and population compare for major interstate utilities, municipal cooperatives, industrial owners, and other groups?

7. What would be the difference in cost (and why) for removing within 10 years the PCBs from the transformers through reclassification and disposing of the transformers, versus disposing of the transformers without reclassification at the end of their useful life?

8. How much equipment is being used indoors? How much equipment is being used outdoors?

9. Geographically and topographically exactly where, in the form of global positioning system coordinates or maps, is the PCB-containing equipment located? What is the age of the PCB-containing equipment at each of these locations?

10. What active or passive safety systems and equipment are installed and operating for PCB-containing equipment, including dikes, berms, safety valves, expansion chambers, remote monitoring systems and capture basins?

B. Populations of Electromagnets, Switches, and Voltage Regulators (Containing Greater Than 2 Fluid Ounces of Dielectric Fluid)

1. What percentage of your entire electromagnets, switches, and voltage regulators inventory in use or stored for reuse was manufactured each year between 1950 and 1980, all years up to 1949, and all years from 1981 to 2007? If this information is not available, please provide alternative information, such as: What percent of the entire transformer inventory is 30 years old, 40 years old, and 50 years old?

2. What percentage of the electromagnets, switches, and voltage regulators population contains dielectric fluid with PCB concentrations ≥ 50 ppm PCB? How many units are in each population? How does the percentage and population compare for major interstate utilities, municipal cooperatives, industrial owners, and other groups?

3. The original use authorization for electromagnets was for a very restricted number of known applications in coal mine processing operations. How many electromagnets in these coal mining operations still use PCBs?

4. For electrical utilities and other owners, have you tested all potentially (based on year of manufacture and other information) contaminated electromagnets, switches, and voltage regulators? Do you know where all regulated PCB-containing electromagnets, switches, and voltage regulators are currently located? Have you removed all askarel containing PCB electromagnets, switches, and voltage regulators? Have you removed all mineral oil containing PCB electromagnets, switches, and voltage regulators? Have you removed all mineral oil containing PCB-contaminated electromagnets, switches, and voltage regulators?

5. What would be the difference in cost (and why) for removing the PCB-containing electromagnets, switches, and voltage regulators and disposing of them within 10 years, versus disposing of the electromagnets, switches, and voltage regulators at the end of their useful life?

6. How much equipment is being used indoors? How much equipment is being used outdoors? Geographically and topographically exactly where, in the form of global positioning system coordinates or maps, is the PCB-containing equipment located?

7. What is the age of the PCB-containing equipment at each of these locations?

8. What active or passive safety systems and equipment is installed and operating, including dikes, berms, safety valves, expansion chambers, and capture basins?

C. Populations of Electrical Capacitors (Containing Greater Than 2 Fluid Ounces of Dielectric Fluid)

1. What percentage of your entire capacitor inventory in use or stored for reuse was manufactured each year between 1950 and 1980, all years up to 1949, and all years from 1981 to 2007? If this information is not available, please provide alternative information, such as: What percentage of the entire transformer inventory is 30 years old, 40 years old, or 50 years old?

2. How does the percentage differ of these 30, 40, and 50 year-old and older capacitors for the following applications: Transmission, substation, pole top, and pad mount?

3. What percentage of the total capacitor population is made up of PCB large capacitors? How many units are in this population? How does the percent and population compare for major interstate utilities, municipal cooperatives, industrial owners, and other groups?

4. What percentage of your capacitor population is PCB-contaminated? How many units are in this population? How does the percentage and population compare for major interstate utilities, municipals cooperatives, industrial owners, and other groups?

5. For electrical utilities and other owners, have you tested all potentially (based on year of manufacture and other information) contaminated equipment? Do you know where all regulated PCB equipment is currently located? Have you removed all askarel containing PCB capacitors? Have you removed all mineral oil containing PCB capacitors? Have you removed all mineral oil containing PCB-contaminated capacitors?

6. What would be the difference in cost (and why) for removing the regulated PCB capacitors and disposing them within 10 years as opposed to at the end of the useful life of the capacitors?

7. How many PCB capacitors which are still in active use (not stored for reuse) contain ≥ 2 ounces of dielectric fluid and < 3 lbs. of dielectric fluid?

8. What is the best way to determine whether a capacitor contains ≥ 2 ounces of dielectric fluid other than reading a nameplate or actually draining and weighing the dielectric fluid?

9. What are the most likely minimum dimensions of a capacitor, which contains 2 or more ounces of PCB dielectric fluid?

10. What percentage of the total population of PCB capacitors that are currently in use contain ≥ 0.05 liters (or approximately 1.7 fluid ounces) of dielectric fluid and 1.36 kg. (< 3 lbs.) of dielectric fluid?

11. What would be the difference in cost (and why) for removing within 10 years the PCBs from the PCB capacitors and disposing of them versus disposing of the PCB capacitors at the end of their useful life?

12. How much equipment is being used indoors? How much equipment is being used outdoors? Geographically and topographically exactly where, in the form of global positioning system coordinates or maps, is the PCB-containing equipment located?

13. What is the age of the PCB-containing equipment at each of these locations?

14. What active or passive safety systems and equipment is installed and operating, including dikes, berms, safety valves, expansion chambers, and capture basins?

D. Populations of Circuit Breakers, Reclosers, and Liquid-filled Cable (Containing Greater Than 2 Fluid Ounces of Dielectric Fluid)

1. What percentage of circuit breakers, reclosers, and liquid-filled cables inventory in use or stored for reuse was manufactured each year between 1950 and 1980, all years up to 1949, and all years from 1981 to 2007? If this information is not available, please provide alternative information, such as:

What percent of the entire transformer inventory is 30 years old, 40 years old, and 50 years old?

2. What percentage in each population of your circuit breakers, reclosers, and liquid-filled cable population contains dielectric fluid with PCB concentrations ≥ 50 ppm is PCB? How many units are in each population?

3. For electrical utilities and other owners, have you tested all potentially contaminated breakers, reclosers, and liquid-filled cables? Do you know where all regulated PCB breakers, reclosers, and liquid-filled cables are currently located? Have you removed all circuit breakers, reclosers, and liquid-filled cables containing mineral oil with ≥ 50 ppm PCBs-contaminated circuit breakers, reclosers, and liquid-filled cables?

4. What would be the difference in cost (and why) for removing within 10 years the PCB breakers, reclosers, and liquid-filled cables and disposing of them versus disposing of the PCB breakers, reclosers, and liquid-filled cables at the end of their useful life?

5. How much equipment is being used indoors? How much equipment is being used outdoors? Geographically and topographically exactly where, in the form of global positioning system coordinates or maps, is the PCB-containing equipment located?

6. What is the age of the PCB-containing equipment at each of these locations?

7. What active or passive safety systems and equipment is installed and operating, including dikes, berms, safety valves, expansion chambers, and capture basins?

E. Populations of Rectifiers (Containing Greater Than 2 Fluid Ounces of Dielectric Fluid)

1. What percentage of your rectifiers inventory in use or stored for reuse was manufactured each year between 1950 and 1980, all years up to 1949, and all years from 1981 to 2007? If this information is not available, please provide alternative information, such as: What percentage of the entire rectifier inventory is 30 years old, 40 years old, and 50 years old?

2. What percentage of your rectifier population contains dielectric fluid with PCB concentrations ≥ 50 ppm PCBs? How many units are in this population?

3. What percentage of your rectifier population is PCB-contaminated? How many units are in this population?

4. For electrical utilities and other owners, have you tested all potentially contaminated rectifiers? Do you know where all regulated PCB rectifiers are currently located? Have you removed all askarel PCB rectifiers? Have you removed all rectifiers containing mineral oil with ≥ 500 ppm PCBs? Have you removed all rectifiers containing mineral oil with ≥ 50 ppm and < 500 ppm PCBs?

5. What percent of electrical utilities and other owners has removed all mineral oil PCB rectifiers?

6. What percent of electrical utilities and other owners has removed all mineral oil PCB-contaminated rectifiers?

7. What would be the estimated cost (and why) for removing these PCB rectifiers and disposing of them within 10 years as opposed to at the end of the useful life of the rectifiers?

8. How much equipment is being used indoors? How much equipment is being used outdoors? Geographically and topographically exactly where, in the form of global positioning system coordinates or maps, is the PCB-containing equipment located?

9. What is the age of the PCB-containing equipment at each of these locations?

10. What active or passive safety systems and equipment is installed and operating, including dikes, berms, safety valves, expansion chambers, and capture basins?

F. Servicing

1. How long does servicing extend the useful service life of each type of equipment?

2. How does servicing alter the likelihood of equipment failures?

3. How does servicing change the ultimate likelihood of the release of PCBs?

G. Failure of Vintage PCB-Containing Electrical Equipment

1. How do failure rates differ for equipment which has been rebuilt or serviced in particular ways, relative to equipment that remains substantially as it was originally installed?

2. EPA seeks information to project the rate, location, and amount of PCB releases, and the causes of the releases. For example, what are the risks of failure involving electrical surges, insulation failure, or electrical fires as compared to the rupture of the tanks containing the PCBs?

3. What percentage of the entire transformer inventory, which was in use or storage for reuse and which was manufactured before July 31, 1979, failed in the following time periods:

a. All years between January 1, 1940 and December 31, 1949;

b. Each year between 1950 and 1980; and

c. All years between January 1, 1981 and December 31, 2008?

4. If this information is not available, please provide information for alternate time intervals.

5. What forms of preventive maintenance or remote monitoring are used to warn owners or operators of a potential or impending equipment failure?

6. With respect to a company's PCB-containing equipment, on what equipment are these or other preventive maintenance or remote monitoring techniques employed?

7. For drainable and refillable mineral oil containing PCB articles, how do the purchase price and operational costs for this approach compare to reclassification for transformers or reclassifiable equipment?

8. How do failure rates differ for equipment which has been rebuilt or serviced in particular ways, compared to equipment that remains substantially as it was originally installed?

9. What have been and are the insurance costs for the replacement of failed PCB-containing equipment and cleanup of PCB spills from this equipment over the past 30 years?

10. How would these insurance costs for the replacement of failed PCB-containing equipment and cleanup of PCB spills from this equipment be expected to change in the next 20 years?

H. Damage to Equipment During Severe Weather Events

1. What kind of steps can be taken to prevent release of dielectric fluid from damage during adverse severe weather events such as hurricanes, tornados, floods, and earthquakes?

2. What is the cost per unit of these steps compared to the cost of: Removal and disposal of askarel containing units; or reclassification or removal and disposal of the mineral oil containing units?

3. What is the cost to cleanup an average catastrophic weather release of dielectric fluid and the disposal of the waste and the equipment plus any damages to private or public property?

4. How does this cleanup and related costs compare to the cost of: Removal and disposal of askarel containing units; or reclassification or removal and disposal of the mineral oil containing units?

5. What have been and are the insurance costs as the result of damage from severe weather events for the replacement of failed PCB-containing equipment and cleanup of PCB spills from this equipment over the past 30 years?

6. How would these insurance costs as the result of damage from severe weather events for the replacement of failed PCB-containing equipment and cleanup of PCB spills from this equipment be expected to change in the next 20 years?

7. How has the weather-related liability insurance cost changed for owners of PCB-containing equipment over the last 30 years? Over the last 20 years? Over the last 5 years?

8. EPA seeks information on the rate of occurrence of severe weather events involving PCB-containing equipment in each calendar year starting from 1998 until 2008:

a. What types of equipment were involved?

b. Where was the equipment located (indoors or outdoors)?

c. Did spills occur as a result of the severe weather events?

d. What was the amount released in gallons of liquid, and if PCBs were presents what was the concentration in ppm?

e. How much liquid was contained and recovered?

f. What human health or environmental exposure and effects were observed or recorded?

g. How were the exposures and effects estimated or measured?

I. Alternatives to PCB Liquids

1. What are the PCB substitutes currently available commercially?

2. What are the human health and environmental effects of exposure to PCB substitutes when they are released to the environment?

3. What are the human health and property damage risks due to the flammability properties of the PCB substitutes?

4. What is the likelihood that equipment containing the PCB substitutes have releases of the substitute materials, compared with the likelihood that equipment containing PCBs have releases of PCBs?

5. What other information about PCB substitutes is available that would inform EPA's consideration of the trade-offs that would be required by a PCB phaseout?

J. Removal and Replacement Costs

1. How many PCB liquid disposal companies have been operating at the end of each year for the last 10 years?

2. How many PCB equipment (drained or undrained) disposal companies have been operating at the end of each year for the last 10 years?

3. What has the average disposal cost been for a gallon of PCB oil containing ≥ 50 ppm and < 500 ppm at the end of each year for the last 10 years?

4. What has been the average disposal cost for a gallon PCB oil containing from ≥ 500 ppm to ≤ 10,000 ppm at the end of each year for the last 10 years?

5. What has been the average disposal cost for a gallon or of askarel oil containing > 100,000 ppm PCBs at the end of each year for the last 10 years?

6. What has been the average cost per ton for disposing of drained, oil-filled equipment, which contained ≥ 50 ppm and < 500 ppm PCB at the end of each year for the last 10 years?

7. What has been the average cost per ton for disposing of drained, oil-filled equipment which contained ≥ 500 ppm PCB at the end of each year for the last 10 years?

8. What has been the average cost per ton for disposing of drained askarel-filled equipment > 100,000 ppm PCB at the end of each year for the last 10 years?

9. What has been the average cost per pound, per ton, or per kilovolt amp (KVA) been for recycling the metal from drained oil-filled transformers which contained ≥ 50 ppm and < 500 ppm PCB at the end of each year for the last 10 years?

10. What sorts of incentives might enable organizations with limited budgets to remove regulated PCBs and PCB equipment for their systems and facilities?

K. PCB Waste Disposal Capacity

1. What has been the permitted PCB disposal capacity for liquid PCBs for companies which have been operating at the end of each year for the last 10 years?

2. At what average percent of permitted PCB disposal capacity have the PCB liquid disposal companies operated per year for the last 10 years?

3. What has been the permitted PCB disposal capacity for drained PCB equipment for companies which have been operating at the end of each year for the last 10 years?

4. At what average percent of permitted PCB disposal capacity have the drained PCB equipment disposal companies operated per year for the last 10 years?

5. For a transformer containing 100 gallons of 250 ppm oil, how does the cost compare for:

a. Reclassifying to a non PCB transformer (draining, refilling with new/clean oil, and disposing of the PCB oil and reusing the transformer)? Reclassifying to a transformer containing < 1 ppm PCBs?

b. Disposing of the oil and landfilling the drained transformer?

c. Disposing of the oil and recovering the metal for recycling?

L. Current Management Practices for Equipment (Other Than Equipment Included in Unit XIV.A.-F.)

1. If you are a PCB equipment owner, which of the following have you completed:

a. Identified all PCB-containing equipment?

b. Routinely tested equipment for its PCB content?

c. Tested all equipment known or assumed to contain PCBs?

d. Reclassified known PCB equipment or equipment, which is newly tested and found to be positive for PCBs?

e. Disposed of, without recycling metals, known PCB equipment, or equipment which is newly tested and found to be positive for PCBs?

f. Disposed of, to include recycling metals, known PCB equipment, or equipment which is newly tested and found to be positive for PCBs?

g. Distributed in commerce to someone else for use known PCB equipment, or equipment which is newly tested and found to be positive for PCBs?

h. Recorded the locations of all equipment or a particular type of equipment, such as transformers or capacitors, containing > 500 ppm PCBs?

i. Recorded the locations of all of a particular type of equipment, such as transformers containing > 50 ppm PCBs?

j. Recorded the locations of all of a particular type of equipment, such as transformers containing > 1 ppm PCBs?

k. Tested all mineral oil containing equipment, or a particular type of equipment (such as transformers), which was manufactured before 1979?

l. Labeled all PCB-containing equipment, even though PCB equipment containing < 500 ppm is not required to be marked?

m. Removed from service and disposed of all PCB-containing equipment or a particular type of equipment (such as PCB-contaminated transformers or PCB large capacitors)?

2. What are the costs associated with such activities in question No. 1 in Unit XIV.L.?

3. What are the costs of the practice of preventive maintenance and the re-building of equipment to meet changing service requirements and/or industry or company codes?

4. How well does preventive maintenance or rebuilding effect extension of the expected service life of equipment?

M. Equipment Containing Non-liquid PCBs

1. What is the total number of units (liquid filled plus non-liquid filled) in

each equipment category, such as transformers?

2. What total number of non-liquid units in each equipment category, such as transformers, is in each of these PCB concentration ranges: ≥ 1 ppm and < 50 ppm, ≥ 50 ppm and < 500 ppm, ≥ 500 ppm and < 100,000 ppm, and ≥ 100,000 ppm?

For example, fill in the following table:

Category	Total number of liquid filled plus non-liquid filled units in population	Number of non-liquid filled units with ≥ 1 parts per million (ppm) and < 50 ppm PCBs	Number of non-liquid filled units with ≥ 50 ppm and < 500 ppm PCBs	Number of non-liquid filled units with ≥ 500 ppm and < 100,000 ppm PCBs	Number of non-liquid filled units with ≥ 100,000 ppm PCBs
Transformers	1,000	0	2	0	0
Capacitors	200	0	0	0	10
Etc.					

3. What is the difference in the locations used for liquid filled units, versus non-liquid filled units located?

4. How much does it cost to test (sample collection, extraction, chemical analysis, and recordkeeping) non-liquid filled equipment to determine the PCB concentration?

5. Other than chemical analysis, what methods (such as application type, nameplate, model number, manufacturer name, etc.) can be used to identify PCB containing non-liquid filled equipment?

N. Damage Due to Vandalism or Theft

1. What types of equipment were involved?

2. Where was the equipment located (indoors or outdoors)? Did spills occur as a result of the vandalism?

3. What was the amount released in gallons of liquid, and if PCBs were present what was the concentration in ppm?

4. How much liquid was contained and recovered?

5. What human health or environmental exposure and effects were observed or recorded?

6. How were the exposures and effects which were reported in response to question No. 5 in Unit XIV.N. estimated or measured?

7. What have been and are the insurance costs as the result of vandalism or theft for the replacement of failed PCB-containing equipment and cleanup of PCB spills from this equipment over the past 30 years?

8. How would these insurance costs as the result of vandalism or theft for the replacement of failed PCB-containing equipment and cleanup of PCB spills from this equipment change in the next 20 years?

O. Reclassification of Askarel Transformers

1. If you have attempted to reclassify an askarel-filled unit and have been unsuccessful, how long did you spend draining and refilling and how many times did you drain and refill when PCBs still “leached back” to a concentration ≥ 500 ppm for each unit?

2. What was the cost of each unsuccessful reclassification?

3. How many askarel transformers or other askarel PCB articles (such as voltage regulators) have you reclassified successfully to PCB-contaminated status or non-PCB status?

4. For each piece of successfully reclassified askarel-filled equipment, how many times was it necessary to drain and refill the equipment?

5. For each piece of successfully reclassified askarel-filled equipment, if the equipment was also flushed, what flushing procedure did you use?

6. For each piece of successfully reclassified askarel-filled equipment, how long did it take to reclassify the equipment from the first drain and refilling to a permanent PCB measurement at the new regulatory status of PCB-contaminated or non-PCB? How often was reclassification later proven to be unsuccessful, because PCBs leached back above the target reclassification level?

7. What was the cost of each successful reclassification?

P. Railroad Transformers

1. In what railroad systems are PCB transformers and PCB-contaminated transformers still in use as railroad transformers?

2. What percentage of railroad transformers are PCB transformers?

3. How many railroad transformers are PCB transformers?

4. What percentage of railroad transformers are PCB-contaminated transformers?

5. How many railroad transformers are PCB-contaminated transformers?

6. What is the expected life of a transformer now in service as a railroad transformer before it requires routine servicing of the dielectric fluid?

7. What would be the difference in cost (and why) for removing within 10 years the PCBs from the railroad transformers through reclassification and disposing of them versus disposing of the railroad transformers without reclassification at the end of their useful life?

Q. Mining Equipment

1. At what locations and for what applications are PCBs currently used in mining equipment?

2. What percent of these pieces of equipment, which are found in these applications, contain PCBs?

3. How many pieces of equipment in these applications contain PCBs?

4. What would be the difference in cost (and why) for removing within 10 years the PCBs from the mining equipment and disposing of them versus disposing of the mining equipment at the end of their useful life?

R. Use of Contaminated Porous Surfaces

1. What has the average per ton, drum, or cubic yard disposal cost been to dispose of contaminated non-liquid material (such as soil or concrete) from a spill of PCB oil containing ≥ 50 ppm each year for the last 10 years? Please differentiate costs based on PCB concentration (e.g., < 50 ppm PCB waste, ≥ 50 ppm, etc.) and based on type of disposer (e.g., landfill, incinerator, etc.).

2. How often is there a planned major outage to equipment mounted on concrete pads or floors? How long is such a planned outage?

S. Use in Natural Gas Transmission and Distribution Systems

1. How many gallons of ≥ 50 ppm condensate have been removed and disposed of annually from natural gas pipelines owned by each individual gas transmission company and distribution company starting in 1998?

2. Do transmission companies regularly test the condensate for PCBs? If so, what is done with the PCBs when found?

3. What locations in the system have the most condensate removed?

4. What time of year is most condensate removed?
5. How do natural gas transmission and distribution companies test for PCBs in dry systems?

T. Storage for Reuse of PCB Articles

1. How many pieces of in-use equipment are the stored equipment items being kept to replace?
2. Where is the equipment which is to be replaced by the stored equipment located with respect to other potential indoor secure storage areas?
3. What is the historical lifetime and turnover (removal from storage for disposal) rate per year of the in-use equipment?
4. When do owners plan to replace this in-use equipment with non-PCB equipment or reclassify this in-use equipment?
5. When do owners plan to replace the stored equipment with non-PCB equipment or reclassify this stored equipment?
6. What is the annualized cost of storing and managing this equipment?
7. What would be the cost of replacement of this equipment?
8. What would be the cost of reclassifying this equipment, where authorized?
9. What is the likelihood and consequences of service interruptions and loss of revenue if these replacement devices were not available at the site of the equipment to be replaced?
10. What is the history (number of occurrences, dates, amounts and cost to clean up) of spills or other releases of PCBs from this equipment, which is being stored for reuse?

U. Distribution in Commerce

1. What is the annual sale price or dollar value and what is the number of units which were distributed in commerce each year over the last 5 years of used but working askarel-filled equipment?
2. What is the annual sale price or dollar value and what is the number of units which were distributed in commerce each year over the last 5 years of used but working mineral oil filled PCB (≥ 500 ppm) equipment?
3. What is the annual sale price or dollar value and what is the number of units which were distributed in commerce each year of used but working mineral oil filled PCB-contaminated (≥ 50 ppm and < 500 ppm) equipment?
4. How many units of regulated PCB-electrical equipment were sold each year over the last 5 years for domestic scrap metal recovery?
5. How many units of regulated PCB-electrical equipment were sold each year over the last 5 years for foreign scrap metal recovery?
6. How many units of regulated PCB-electrical equipment were exported for use each year over the last 5 years for use?
7. What has been the average purchase price of a new or rebuilt (PCB-free) 100 KVA mineral oil filled transformer and a new (PCB-free) 100 KVAR capacitor every year over the last 10 years?
8. How different is the average purchase price of new or rebuilt (PCB-free) larger or smaller transformers and capacitors?
9. What is the average number of days between an order and delivery for a new or rebuilt replacement PCB-free 100 KVA transformer and a new replacement PCB-free 100 KVAR capacitor every year over the last 10 years?
10. How long does it take for a delivery for a replacement for a new or rebuilt PCB-free large (> 250 KVA) transformer, a smaller (< 250 KVA) transformer, and larger (> 1.36 kg [3 lbs.] of dielectric fluid) capacitors?

V. Excluded Manufacturing Processes

1. How many excluded manufacturing processes are currently operating or, if not currently operating, expect to be operating in the next 5 years?
2. What is the estimated total annual weight in tons of PCBs produced each year over the last 5 years and in the next 5 years in each of the following categories: Products, solid waste, waste water, and air emissions?
3. What are the type and volume of PCB products that would be affected by such changes in the definition, as well as the cost, economic, and other impacts of these changes?

W. Recycled PCBs

1. In any of the last 5 years have you anyone found PCBs at concentrations ≥ 1 ppm in recycled paper? How often? What was the source of the feedstock paper?
2. What steps can be taken or have been taken to reduce the PCB concentration in recycled paper?
3. What is the cost of implementing these steps to reduce the PCB concentration in recycled paper if they have not already been implemented?
4. What are the type and volume of PCB products that would be affected by a potential change in the definition of recycled paper (required to contain less than 1 ppm PCBs), as well as the cost, economic, and other impacts of these changes?

X. Reconsideration of the Use of the 50 ppm Level for Excluded PCB Products (e.g., Caulk)

1. What should the maximum PCB concentration, if any, be for the "excluded PCB products" as defined in 40 CFR 761.3?
2. What should the minimum PCB concentration be for the "excluded PCB products" as defined in 40 CFR 761.3?
3. Should there be a new separate use authorization for certain currently excluded PCBs found in certain products such as paint, gaskets, or caulk?
4. What types of non-liquid products (adhesives, caulk, coatings, grease, paint, rubber/plastic electrical insulation, gaskets, sealants, waxes, etc.), which were manufactured before 1979 and are currently in use, contain PCBs at concentrations between 1 ppm and 50 ppm?
5. What types of liquid products (pump oil, solvent, or other fluid), other than those authorized for use in 40 CFR 761.30, contain PCBs at concentrations between 1 ppm and 50 ppm?
6. For each class of non-liquid and liquid product, what percent of the overall product market share is taken by the PCB-containing product?
a. What is the estimated total weight or volume of each type of product in current use?
b. What kinds of use has each product been applied to, on, or in?
c. What is the geographic distribution of each product use?
d. What is the average expected lifetime of the product?
e. When would the product normally be replaced as part of preventive maintenance?

Y. Use of PCB-Containing Electrical Equipment Parts

1. What PCB-containing spare parts, such as bushings and other ancillary equipment, are currently needed for what equipment?
2. What is the feasibility of reclassifying PCB-containing spare parts?
3. What is the annualized cost of storing and managing PCB-containing spare parts?
4. What would be the cost of replacement of PCB-containing spare parts?
5. What are the likelihood and consequences of service interruptions and loss of revenue if the PCB-containing spare parts were not available?
6. Where are these spare parts located geographically in relation to the equipment they will be used on?

7. In what industrial or commercial settings can the equipment, which the spare parts will be used on, be found?

Z. Reassessment of the Possible Authorization of the Use of Some Non-Liquid PCB-Containing Products

1. What comments can you provide that will inform EPA as to whether to authorize or not authorize the use of caulk, paint, or other non-liquid PCB product at concentrations exceeding the level of 50 ppm currently provided in the PCB regulations for excluded PCB products?
2. What data or other information is available on which to evaluate the risks and benefits of the use of PCB-containing caulk, paint, or other non-liquid PCB product?
3. What PCB concentrations should be authorized for the use of PCB-containing caulk, paint, or other non-liquid PCB products?

AA. PCBs on Maritime Vessels

1. In what vessel systems is PCB-containing equipment still in use on vessels?
2. What percentage of vessel equipment uses liquid PCBs?
3. What percentage of vessel equipment uses non-liquid PCBs?
4. What is the expected life of equipment containing PCBs on vessels now in service before it requires routine servicing?
5. What is the difference in the locations used for liquid filled equipment, versus non-liquid filled equipment located?
6. How much does it cost to identify and test (sample collection, extraction, chemical analysis, and recordkeeping) liquid filled equipment and/or non-liquid filled equipment on vessels to determine the PCB concentration?
7. Other than chemical analysis, what methods (such as application type, nameplate, model number, manufacturer name, etc.) can be used to identify PCB-containing equipment?
8. Do non-liquid PCBs enclosed in cabling pose any greater risk to the health of the public than liquid PCBs enclosed in cabling?
9. Should the "totally enclosed" exemption accorded to liquid PCBs enclosed in cabling be extended to solid PCBs?

XV. References

As indicated under **ADDRESSES**, a docket has been established for this rulemaking under docket ID number EPA–HQ–OPPT–2009–0757. The following is a listing of the documents that are specifically referenced in this document. The docket includes these documents and other information considered by EPA in developing this ANPRM, including documents that are referenced within the documents that are included in the docket, even if the referenced document is not physically located in the docket. For assistance in locating these other documents, please consult the technical person listed under **FOR FURTHER INFORMATION CONTACT**.

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XVI. Statutory and Executive Order Reviews

Under Executive Order 12866, entitled ''Regulatory Planning and Review'' (58 FR 51735, October 4, 1993), this action was submitted to the Office of Management and Budget (OMB) for review. Any changes to the document that were made in response to OMB comments received by EPA during that review have been documented in the docket as required by the Executive Order.

Since this document does not impose or propose any requirements, and instead seeks comments and suggestions for the Agency to consider in possibly developing a subsequent proposed rule, the various other review requirements that apply when an agency imposes requirements do not apply to this action. Nevertheless, as part of your comments on this document, you may include any comments or information that you have regarding the various other review requirements.

In particular, EPA is interested in any information that would help the Agency to assess the potential impact of a rule on small entities pursuant to the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*); to consider voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, section 12(d) (15 U.S.C. 272 note); to consider environmental health or safety effects on children pursuant to Executive Order 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997); or to consider human health or environmental effects on minority or low-income populations pursuant to Executive Order 12898, entitled ''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations'' (59 FR 7629, February 16, 1994).

The Agency will consider such comments during the development of any subsequent proposed rule as it takes appropriate steps to address any applicable requirements.

List of Subjects in 40 CFR Part 761

Environmental protection, Hazardous substances, Labeling, Polychlorinated biphenyls (PCBs), Reporting and recordkeeping requirements.

Dated: March 31, 2010.

Lisa P. Jackson,

Administrator.

[FR Doc. 2010–7751 Filed 4–6–10; 8:45 am]

BILLING CODE 6560–50–S

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

[Docket No. FWS-R8-ES-2008-0067]
[MO 92210-0-0008-B2]

Endangered and Threatened Wildlife and Plants; 12-Month Finding on a Petition to Reclassify the Delta Smelt From Threatened to Endangered Throughout Its Range

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of 12–month petition finding.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce a 12–month finding on a petition to reclassify the delta smelt (*Hypomesus transpacificus*) under the Endangered Species Act of 1973, as amended. After review of all available scientific and commercial information, we find that reclassifying the delta smelt from a threatened to an endangered species is warranted, but precluded by other higher priority listing actions. We will develop a proposed rule to reclassify this species as our priorities allow.

DATES: The finding announced in this document was made on April 7, 2010.

ADDRESSES: This finding is available on the Internet at *http://www.regulations.gov* at Docket Number FWS–R8–ES–2008–0067. Supporting documentation we used in preparing this finding is available for public inspection, by appointment, during normal business hours at the U.S. Fish and Wildlife Service, Sacramento Fish and Wildlife Office, 2800 Cottage Way, W-2605, Sacramento, CA 95825. Please submit any new information, materials, comments, or questions concerning this finding to the above address.

FOR FURTHER INFORMATION CONTACT: Mary Grim, San Francisco Bay-Delta Fish and Wildlife Office, 650 Capitol Mall, 5th Floor, Sacramento, CA 95814; by telephone at 916-930-5634; or by facsimile at 916-414-6462. If you use a telecommunications device for the deaf (TDD), call the Federal Information Relay Service (FIRS) at 800-877-8339.

SUPPLEMENTARY INFORMATION:

Background

Section 4(b)(3)(A) of the Endangered Species Act of 1973, as amended (Act) (16 U.S.C. 1531 *et seq.*) requires that, for any petition to add a species to, remove a species from, or reclassify a species on one of the Lists of Endangered and Threatened Wildlife and Plants, we first make a determination whether the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted. To the maximum extent practicable, we make this determination within 90 days of receipt of the petition, and publish the finding promptly in the **Federal Register**.

If we find the petition presents substantial information, section 4(b)(3)(A) of the Act requires us to commence a status review of the species, and section 4(b)(3)(B) of the Act requires us to make a second finding, this one within 12 months of the date of receipt of the petition, on whether the petitioned action is: (a) Not warranted, (b) warranted, or (c) warranted, but the immediate proposal of a regulation implementing the petitioned action is precluded by other pending proposals to determine whether any species is threatened or endangered, and expeditious progress is being made to add or remove qualified species from the Lists of Endangered and Threatened Wildlife and Plants. We must publish these 12–month findings in the **Federal Register**.

Species for which listing is warranted but precluded are considered to be "candidates" for listing. Section 4(b)(3)(C) of the Act requires that a petition for which the requested action is found to be warranted but precluded be treated as though resubmitted on the date of such finding, i.e., requiring a subsequent finding to be made within 12 months. Each subsequent 12–month finding is also to be published in the **Federal Register**. We typically publish these findings in our Candidate Notice of Review (CNOR). Our most recent CNOR was published on November 9, 2009 (74 FR 57804).

Previous Federal Action

We were originally petitioned to list the delta smelt as endangered on June 26, 1990. We proposed the species as threatened and proposed the designation of critical habitat on October 3, 1991 (56 FR 50075). We listed the species as threatened on March 5, 1993 (58 FR 12854), and we designated critical habitat on December 19, 1994 (59 FR 65256). The delta smelt was one of eight fish species addressed in the November 26, 1996, *Recovery Plan for the Sacramento–San Joaquin Delta Native Fishes* (Service 1996, pp. 1-195). We completed a 5–year status review of the delta smelt on March 31, 2004 (Service 2004, pp. 1-50).

On March 9, 2006, we received a petition to reclassify the listing status of the delta smelt, a threatened species, to endangered on an emergency basis. We sent a letter to the petitioners dated June 20, 2006, stating that we would not be able to address their petition at that time because further action on the petition was precluded by court orders and settlement agreements for other listing actions that required us to use nearly all of our listing funds for fiscal year 2006. We also stated in our June 20, 2006, letter that we had evaluated the immediacy of possible threats to the delta smelt, and had determined that an emergency reclassification was not warranted at that time.

On July 10, 2008, we published a 90–day finding that the petition presented substantial scientific information to indicate that reclassifying the delta smelt may be warranted (73 FR 39639). We announced the initiation of a status review at that time, and requested comments and information from the public on or before September 8, 2008. We reopened the comment period on December 9, 2008, and that comment period closed February 9, 2009 (73 FR 74674).

Species Information

Description and Taxonomy

Delta smelt are slender-bodied fish, generally about 60 to 70 millimeters (mm) (2 to 3 inches (in)) long, although they may reach lengths of up to 120 mm (4.7 in) (Moyle 2002, p. 227). Delta smelt are in the Osmeridae family (smelts) (Stanley *et al.* 1995, p. 390). Live fish are nearly translucent and have a steely blue sheen to their sides (Moyle 2002, p. 227). Delta smelt feed primarily on small planktonic (free-floating) crustaceans, and occasionally on insect larvae (Moyle 2002, p. 228). Delta smelt usually aggregate into loose schools, but their discontinuous stroke-and-glide swimming behavior likely makes schooling difficult (Moyle 2002, p. 228).

The delta smelt is one of six species currently recognized in the *Hypomesus* genus (Bennett 2005, p. 8). Within the genus, delta smelt is most closely related to surf smelt (*H. pretiosis*), a species common along the western coast of North America. In contrast, delta smelt is a comparatively distant relation to the wakasagi (*H. nipponensis*), which was introduced into Central Valley

PGE Exhibit 802 – 2018-2016 Incremental FTE Explanations

Driver	Department	Title	Increment Request	Description
Compliance	RC 364 Utility Asset Management	Analyst	1.00	Provide analytical support for T&D increases in capital work. Support Utility Asset Management with program evaluation and data modeling. This position is needed to provide support for evaluation of capital projects for transmission hardening, capital improvement programs, and engineering evaluation support. Joint Inspection is a new program endorsed by the OPUC. The electric pole owner inspects all attachments on their poles as well as any communications poles in the map grid and provides physical corrections for National Electric Safety Code (NESC) violations where practicable. This results in one trip to the pole instead of 2-8 trips.
Compliance	RC 364 Utility Asset Management	Lighting Materials Project	1.00	Facilitate critically essential functions necessary to meet expectations of PGE's builder developer customers and Municipalities within our service territory. This position would be responsible for reviewing, analyzing, and consolidating PGE's luminaire and pole options offered to municipal and area light customers. This position is needed to address immediate customer satisfaction pain points (municipality, developer, and contractor) related to PGE's luminaire offerings, stocking levels, and installation commitments. Joint Inspection is a new program endorsed by the OPUC. The electric pole owner inspects all attachments on their poles as well as any communications poles in the map grid and provides physical corrections for National Electric Safety Code (NESC) violations where practicable. This results in one trip to the pole instead of 2-8 trips.
Compliance	RC 364 Utility Asset Management	Project Manager	1.00	This position will be responsible for managing PGE's wireless collocation business and supporting our Joint Inspection and Correction program, which kicked off as a pilot program in 2016. On average, PGE receives about 60 wireless collocation (upgrades, repairs, new site) requests per year. Wireless make-ready (due to equipment, shutdown, coordination with customers, and contract requirements) can take anywhere from 6-18 months to complete. With the new systems and processes, a wireless designer can complete about 25-30 collocations per year, depending on the complexity of requests. Joint Inspection is a new program endorsed by the OPUC. The electric pole owner inspects all attachments on their poles as well as any communications poles in the map grid and provides physical corrections for National Electric Safety Code

				(NESC) violations where practicable. This results in one trip to the pole instead of 2-8 trips.
Compliance	RC 594 Substation Operation Technology	Specialist, Operations and Planning Coordinator	1.00	The position is required to support NERC compliance with operations and planning standards for all of substation operations. The specialist will be the backup owner for all substation operations standards, including PRC-005, PRC-004, FAC-501 and others. The position will close gaps identified during our self-report and mitigation plan for PRC-005. They will also allow PGE to be proactive with NERC standards development to protect PGE’s interest with regards to future regulations.
Compliance	RC 595 T&D Planning	Engineer, T&D Planning	1.00	The NERC compliance standards governing transmission continue to expand, requiring additional engineering resources to successfully fulfill PGE's compliance obligations. This includes new requirements for advanced studies such as geomagnetic disturbances and earthquake resiliency, as well as greater coordination of construction plans and transmission outage scheduling. Some transmission planning activities are being contracted out; however, the regional coordination aspect for more advanced transmission planning studies requires in-depth knowledge of PGE's system and operating practices. Because the new compliance standards are permanent in nature, a more permanent resource is needed.
Compliance	RC 595 T&D Planning	Specialist, Customer Equipment Violation	1.00	This position is needed to support the Low Clearance program. This program is a new regulatory requirement to address low services within PGE's service territory. In January 2015, the OPUC notified all Oregon electric utilities that overhead services with less than 10 feet of clearance to ground are in violation of the National Electric Safety Code (NESC) and would need to be corrected. In their notification, the OPUC explained that as a result of a recent IEEE interpretation of a clearance code in the 1961 edition of the NESC, electric utilities had mistakenly applied “grandfathering” to these services. Using data from recent inspections, it is estimated that 32,000 services within PGE’s territory must be corrected as a result of this ruling. The overwhelming majority of these violations are the result of customer-owned facilities (weather heads and house brackets) that were installed too low to meet this clearance requirement.

Compliance	RC 595 T&D Planning	Specialist, Field Quality Assurance / Quality Control	1.00	This position is needed to support the Low Clearance program. This program is a new regulatory requirement to address low services within PGE's service territory. In January 2015, the OPUC notified all Oregon electric utilities that overhead services with less than 10 feet of clearance to ground are in violation of the National Electric Safety Code (NESC) and would need to be corrected. In their notification, the OPUC explained that as a result of a recent IEEE interpretation of a clearance code in the 1961 edition of the NESC, electric utilities had mistakenly applied "grandfathering" to these services. Using data from recent inspections, it is estimated that 32,000 services within PGE's territory must be corrected as a result of this ruling. The overwhelming majority of these violations are the result of customer-owned facilities (weather heads and house brackets) that were installed too low to meet this clearance requirement.
Continuous Improvement	RC 018 T&D Special Project	Manager, Continuous Improvement	0.73	This position will manage the following groups: Metrics, Field Technical Services, T&D Project Services, and the Business Systems Administration. These groups make up the Continuous Improvement Projects team. This increases the currently budgeted position to a full-time role.
Continuous Improvement	RC 368 T&D Project Services	Administrator	1.00	Administrative support for the T&D Project Services department as they support Continuous Improvement projects.
Continuous Improvement	RC 368 T&D Project Services	Lead	1.00	This lead role is specific to the Metrics group within the Continuous Improvement team. This role supports and provides metrics to all T&D departments from the various systems used across T&D. This role will also head efforts to merge with PACE reporting over the next one to three years.
Continuous Improvement	RC 368 T&D Project Services	Project Manager	1.00	This position is moving from a sunset position to a FTE position.
Continuous Improvement	RC 376 Business Systems Administration	Analyst, Business	1.00	This is for the Business Systems Administration group as they support the new Continuous Improvement program
Continuous Improvement	RC 451 Field Technical Support	Specialist, Field Technician Support	1.00	This position is to support the increased amount of laptop operations and Automated Vehicle Locator in the field and vehicles and additional crews we are now supporting.
Continuous Improvement	RC 593 Transmission and Reliability Service	Specialist, Business Systems Integration, Settlements, and Billing	1.00	Provide systems and business process integration management for PGE Transmission and Reliability Services (T&RS) participation in bilateral and organized markets to enable efficient work processes. Align T&RS back office processes to support the on-going development and implementation of PGE's Open Access Transmission Tariff, market rules, federal and regional regulations in coordination with T&RS staff.
Customer-	RC 305 Southern	Journeyman	3.00	Linemen added to cover uptick in new connects and customer work.

Driven Capital Work	Line Crews	Lineman		
Customer-Driven Capital Work	RC 305 Southern Line Crews	Working Foreman Lineman	1.00	Linemen added to cover uptick in new connects and customer work.
Customer-Driven Capital Work	RC 312 Eastern Line Crews	Journeyman Lineman	3.00	Linemen added to cover uptick in new connects and customer work.
Customer-Driven Capital Work	RC 312 Eastern Line Crews	Supervisor, Line Field	1.00	Position supervises the Portland Service Center (PSC) line crews in the field, previews jobs before they are assignment to a crew, and meets with customers as needed. The work load at PSC for Line Field Supervisors (FS) requires more capacity than the two FS currently assigned to PSC can effectively handle. The average field checks per day per FS are more than any other Line Crew Center due to the complexity of working in the City Portland, and the amount of commercial customer work.
Customer-Driven Capital Work	RC 312 Eastern Line Crews	Working Foreman Lineman	1.00	Linemen added to cover uptick in new connects and customer work.
Customer-Driven Capital Work	RC 314 Transmission Engineer and Specialized Design	Specialist, Service and Design Project Manager	2.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work.
Customer-Driven Capital Work	RC 315 Customer Power Quality	Critical Response Follow-up	1.00	Prepares and dispatches all T&D work for PGE Special Testers and Reliability Technicians. Create work orders that are high priority due to safety concerns or customer service through the life cycle of the job.
Customer-Driven Capital Work	RC 319 Geospatial Information Services	Specialist, GIS	4.00	These new positions are driven by the As-Built Operational Processes project. The As-Built Operational Processes project was set up to address the technology gaps and lack of process, role clarity, and capacity to process and post work in order to mitigate further backlog accumulation. Project goals include building capacity on the Geospatial Information Services (GIS) and Service and Design teams to ensure efficient and timely processing of work and utilizing best practices among peer utilities and evaluating the current state. The project steering committee has identified a strategy for the operational processes and resources needed to support the work load long-term.

Customer-Driven Capital Work	RC 319 Geospatial Information Services	Supervisor, GIS	1.00	This new position is driven by the rapid expansion of responsibilities and resources in the Geospatial Information Services (GIS) department. New responsibilities are being transferred to GIS from the Service and Design and IT functions of the business that will allow these departments to better focus on their core responsibilities. Given the increased responsibilities and resources in GIS, the existing management structure cannot adequately support supervision and development of employees within GIS and SAM as well as the programs and customers supported by these departments.
Customer-Driven Capital Work	RC 322 T&D Reliability Crews	Reliability Technician	1.00	Reliability Technician performs proactive inspections of overhead and underground T&D facilities for commercial customers with Quality and Reliability Program requirements. Currently PGE only has two Reliability Technicians that are challenged to complete growing annual inspection schedule, and increasing requests from Quality and Reliability Program customers for inspections.
Customer-Driven Capital Work	RC 323 Eastern Service and Design	Specialist, Service and Design Project Manager	1.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work. Also supports the delivery of PCB Replacement Program.
Customer-Driven Capital Work	RC 324 Western Service and Design North	Specialist, Service and Design Project Manager	2.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work. Also supports the delivery of PCB Replacement Program.
Customer-Driven Capital Work	RC 325 Southside Service and Design	Supervisor, Distribution	1.00	This is a supervisor for the Salem Specialize and Design Group. The second supervisor will be able to split the existing group into two departments. This will allow each supervisor more time to effectively coach and train employees, be more involved in project and design decisions, and to have more time for customer outreach.
Customer-Driven Capital Work	RC 326 Central Service and Design West	Specialist, Designer	4.00	Four additional designers are requested to work on the business owned as-built backlog. This backlog is separate from the Continuous Improvement project-owned backlog, and has resulted from insufficient capacity with the existing designers to work on as-built.
Customer-Driven Capital Work	RC 326 Central Service and Design West	Specialist, Service and Design Project Manager	1.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work.
Customer-Driven Capital Work	RC 329 Westside Line Crews	Journeyman Lineman	6.00	Linemen added to cover uptick in new connects and customer work.

Customer-Driven Capital Work	RC 329 Westside Line Crews	Working Foreman Lineman	2.00	Linemen added to cover uptick in new connects and customer work.
Customer-Driven Capital Work	RC 336 Line Planning and Scheduling	Planner / Scheduler	1.00	Plan and schedule all T&D work for PGE and contract line crews. Works closely with Line Dispatchers, Operations/Field Supervisors, and Prerequisite coordination. We are converting the existing contractor position to a permanent position. It has become increasingly more difficult to get qualified contract employees. This increases instability in providing a well-planned, high density, schedule for PGE and Contract Line Crews.
Customer-Driven Capital Work	RC 339 Distribution Job Processing	Assistant	2.00	This position will review and validate line employee time. This will be a resource for line employees and Payroll. The position will also perform administrative tasks specific to the needs of line supervisors such as scheduling Oregon Department of Transportation (ODOT) physicals. Currently, there are no personnel in the regions to support timesheet entry or monitor time sheet accounting entry. Adding additional administrative assistance will reduce management costs associated with Corporate Planning, Claims Specialist and Line Supervisors who currently respond to time sheet and accounting issues, and will increase employee accountability for time and accounting entry. Adding FTEs will help ensure the estimated 2017 Line Operations combined O&M and Capital union payroll including Standard time, Over Time and premium pay, and will be processed timely and accurately.
Customer-Driven Capital Work	RC 346 Landscape Services	Chemical Spray Truck Driver	1.00	Assist current spray department employees in the mixing, transporting and application of pesticides used in PGE's vegetation management program in substations, generating plants, and company owned properties for compliance with the National Electric Safety Code (NESC). There are currently three spray crew employees applying herbicide to over 200 PGE owned sites. PGE continues to expand the number of facilities in order to fulfill customer demand. In just the last several years, PGE has added five substations, with construction of upcoming Marquam and Rock Creek Substations. However, we are at a point that we can no longer keep up with the weed growth at all sites. We cannot cover all of the locations with three people and stay ahead of the weed growth each year. Having the full two 2-person crew complement will allow us to successfully complete the substation treatments in the spring.

Customer-Driven Capital Work	RC 349 Line Prerequisite Coordination	Specialist, Prerequisite Coordinator	4.00	Supports Planning, Scheduling, and Line Dispatch departments through specialized knowledge of permitting requirements, and managing timing of pre-requisite activities to ensure optimal site readiness for crew arrival. Planning, Scheduling, and Line Dispatch has aimed to prepare a two week schedule, but has frequently been achieving 1-3 days out due to complexities of job preparation. Having a prerequisite coordinator to support the Planner/Scheduler results in denser schedules with longer lead times, fewer turndowns by the crew for site not being ready, more accurate adherence to external jurisdiction permitting requirements, and allows the Planner/Scheduler to focus on managing resource needs and work prioritization and balancing.
Customer-Driven Capital Work	RC 349 Line Prerequisite Coordination	Supervisor, Prerequisite Coordinator	1.00	The Supervisor for the new Line Prerequisite Coordination department is currently filled by a cross-trainer, and is needed as an FTE. Planning, Scheduling, and Line Dispatch have been attempting to provide a full days' schedule for crews since Maximo Mobile and Scheduling implementation. One of the critical enablers to the success of that process was creation of the prerequisite coordinator position, in 2016, and has proven to improve schedule density for crews.
Customer-Driven Capital Work	RC 353 Line Line Dispatch	Specialist, Line Dispatch	1.00	This position is needed to support the New Customer Connection Notification process that notifies customers of scheduled service installation. This is a necessary part of the process to greatly improve customer service. PGE has been trying to cover this work with the use of ongoing cross trainees, but has had difficulty getting qualified applicants. This job also needs a long-term position.
Customer-Driven Capital Work	RC 364 Utility Asset Management	Specialist, Field Inspector	1.00	Field inspectors are responsible for reviewing and analyzing permit requests to attach to PGE and external customer's poles. Field inspectors gather data from poles in the field, to determine through structural analysis, whether the structures are adequate to support proposed attachments. Using accepted design practices and analysis, inspectors ensure that support structures are maintained in compliance with applicable company standards and the National Electric Safety Code (NESC). Field inspectors routinely meet with other utility representatives and PGE General Foremen in the field to help determine the best design for correcting existing code violations and/or make ready for new licensee attachments. Field inspectors are responsible for ensuring that construction was performed in accordance with the design job and that licensees have attached in compliance with PGE requirements. Field inspectors may also be asked to manage projects of a utility or non-utility nature. Joint Inspection is a new program endorsed by the OPUC. The electric pole owner inspects all attachments on their poles as well as any communications poles in the map grid and provides physical corrections for NESC violations where practicable.

				This results in one trip to the pole instead of 2-8 trips resulting in savings for all parties.
Customer-Driven Capital Work	RC 364 Utility Asset Management	Specialist, Joint Use	1.00	Serves as a technical expert on the business operations team and provides operational support of utility Asset Management (UAM) technology, processes, and efficiency. Specific support for the Maximo Joint Use Portal (SharePoint) application, system enhancements and internal process improvements provided by our current employee cross-training in this position have proved very valuable. Therefore, we are making this a FTE position. This position has increased the efficiency of our internal processes through valuable process design work and IT support for PGE employees and allowed UAM to meet our joint use customers' expectations.
Customer-Driven Capital Work	RC 364 Utility Asset Management	Specialist, Service and Design Coordinator	2.00	There are two Service and Design Coordinators (SDC) needed. One SDC is a new position that will be responsible for streamlining street light materials, processes, and special projects that are outside of the normal Project Manager (PM) duties in outdoor lighting. Through customer surveys, and internal metrics it was brought to light, the rapidly changing lighting industry and technology, requires PGE to take an active approach to reducing our fixture offerings in some lines and increasing in others. The other SDC, determined after assessing increased customer demand because of the rising economy, is needed to meet contractor/developer demands. This position is a PM position, responsible for supplying residential development and municipality lighting designs/work orders for new street lighting, required for occupancy.
Customer-Driven Capital Work	RC 366 Central Service and Design East	Specialist, Field Construction Coordinator	1.00	A fifth Field Construction Coordinator (FCC) is requested. Currently the four existing FCCs struggle to keep up with requested inspections and Field Supervisors (FS) provide backup and overflow coverage.
Customer-Driven Capital Work	RC 366 Central Service and Design East	Specialist, Service and Design Project Manager	2.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work. Also supports the delivery of PCB Replacement Program.
Customer-Driven Capital Work	RC 366 Central Service and Design East	Supervisor, Distribution	1.00	This position is to supervise at the Beaverton Line Center and support the increase in customer-driven capital work.
Customer-Driven Capital Work	RC 384 Specialized Design	Analyst, T&D Engineering	1.00	Provide analytical support for T&D increases in capital work. Support Transmission Engineering and Specialized Design with program evaluation and data modeling. In addition, it will provide support for evaluation of capital projects for transmission hardening, capital improvement programs, and engineering evaluation

				support.
Customer-Driven Capital Work	RC 384 Specialized Design	Engineer, Transmission Capital Projects and Planning	1.00	The engineer position will have program level responsibility for PGE's physical transmission assets. This position is needed to continually monitor and evaluate the physical transmission line assets and work to develop capital projects aimed at improving aging or failing infrastructure. This position will act as the engineering program manager with responsibilities for the transmission line inspection program, Transmission Maintenance and Inspection Plan (TMIP) regulatory reporting for FAC-501, Transmission R&D collaboration, and development of transmission projects aimed at correcting issues with aging transmission assets. Other responsibilities will include FERC/NERC compliance, outage/maintenance coordination, transmission asset management support, access road/ROW management, outage planning/prep, restoration planning, and infrastructure hardening.
Customer-Driven Capital Work	RC 384 Specialized Design	Specialist, Designer	1.00	This position will support new capital projects developed within the Transmission Engineering and Specialized Design group. Position will specifically be focused on transmission capital replacement projects, infrastructure hardening, and risk mitigation of existing transmission assets.
Customer-Driven Capital Work	RC 591 SVP Customer Service / T&D	Project Manager	0.73	Conversion of remainder of position to full-time and support the increase in customer work.
Increases in Capital Work	RC 023 System Control Center Support	Engineer, Systems and Control Center	2.00	Provide centralized quality assurance control for the substation operations electronic drawings management systems and asset documentation.
Increases in Capital Work	RC 203 Substation Operations	Engineer, Electric (Maintenance)	1.00	A new resource in substation operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 204 Substation Engineering	Design Engineer (Electric)	1.00	This position is required to address the increases in capital work. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 204 Substation Engineering	Engineer, Electric	3.00	These positions are required to address existing resource shortages and address the increases in capital work. Existing resource shortages in substation operations have been addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety).
Increases in Capital Work	RC 204 Substation Engineering	Project Engineer (Electric)	1.00	A new resource in substation operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.

Increases in Capital Work	RC 204 Substation Engineering	Specialist, Designer	1.00	This position is required to address the increases in capital work. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 204 Substation Engineering	Substation Engineer	1.00	Additional Substation Engineering resource to support increases in capital work. Substation Engineers engineer Substations and provide technical review and oversight of contract substation engineering services.
Increases in Capital Work	RC 204 Substation Engineering	Supervisor	1.00	This position is to provide supervision of Engineering and Drafting personnel who perform engineering design and review of capital Substation projects. An additional manager will be required to provide adequate supervision, work review and employee development as a result of onboarding FTEs to support the increases in capital work.
Increases in Capital Work	RC 204 Substation Engineering	Technician, Drafter	1.00	A new resource in substation operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 209 Substation Technical Services	Relay Station Meter Technician	5.00	This position is required to address an existing resource shortage and address the increases in capital work. Existing resource shortages in Substation Operations have been addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety).
Increases in Capital Work	RC 213 Substation Operations Support	Assistant, Document Control	1.00	This position is to support the increases of capital work. Existing resource shortages in Substation Operations have been addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety).
Increases in Capital Work	RC 213 Substation Operations Support	Specialist, Scheduler	1.00	A new resource in substation operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 214 Substation Civil Construction	Civil Construction	1.00	This position is required to address the increases in capital work. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 216 Substation Maintenance	Contractor General Foreman	2.00	These positions are needed to oversee and coordinate the contract substation construction crews to support the increase in capital work. There are gaps in both the communication and execution of contracted substation construction. While the existing substation GF maintain and improve this process, they will not have the bandwidth to continue this activity with the hiring of additional contractors.
Increases in Capital Work	RC 216 Substation Maintenance	Wireman	6.00	A new resource in Substation Operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in	RC 217 Substation	Substation	1.00	This position is required to address the increases in capital work in regards to

Capital Work	Operators	Operator		substation operations. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 218 Substation Communication Support	Communication Technician	6.00	This position is to support the increases of capital work. Existing resource shortages in Substation Operations have been addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety).
Increases in Capital Work	RC 232 SCADA Technical Services	SCADA Technician	2.00	There is a Supervisory Control and Data Acquisition (SCADA) Technician shortage and demand is only growing. This is a critical position for PGE's participation in the Western EIM, smart grid technologies, and T&D Strategic Asset Management (SAM).
Increases in Capital Work	RC 276 Contract Services & Inspection	Assistant	1.00	Administrative Assistance required for managing T&D contracts from creating requisitions to approval for payment, tracking PUC Service Level Agreement Inspections, Quality Control Programs and Staff processes. The forecasted capital work will raise Contract Services work substantially. Some work including the feeder replacement work for key customers, the Marquam Substation project, PCB transformer testing and replacement, and proactive cable replacement require more outsourcing and therefore, more contract management. Business Systems put in place over the past three years require more accurate and timely data to operate. Our current staffing levels cannot meet those needs for the current work. Strategic planning has established a consistent need for more services that require the additional administrative support.
Increases in Capital Work	RC 276 Contract Services & Inspection	Specialist, Construction Management	1.00	This position will support line operation's construction management and quality control assurance for T&D overhead and underground line construction and maintenance projects. Coordinate and manage contractor resources required to meet needs of Engineering, Service and Design Project Managers (SDPM) and T&D Line Operations. The continued growth in contractor utilization over the past four years has required hiring outside resources to meet quality control needs. Projected growth of capital work over next five year requires resources beyond current staffing. This has resulted in hiring temporary contractors to perform construction management, and Quality Assurance/Quality Control Inspection services. The increased work has generated requests for a higher level of strategy of quality assurance and construction management. This staff is currently the only internal resource with the workforce capable of meeting those needs. In addition, this department faces an exit of three people to retirement. Succession planning is needed to develop skills currently deemed necessary by Project Mangers, Engineering and SDPMs replacements while still preforming the work at increased level of responsibility.
Increases in Capital Work	RC 311 Distribution Engineering	Engineer, Electric	1.00	This position is to engineer substations to support the increases in capital work.
Increases in Capital Work	RC 311 Distribution Engineering	Supervisor, Distribution	2.00	These Supervisor positions (2) are to support the increase in capital work and to address the span of control within Distribution Engineering.

Increases in Capital Work	RC 314 Transmission Engineering and Specialized Design	Engineer	2.00	This position is to support the increases in capital work.
Increases in Capital Work	RC 314 Transmission Engineering and Specialized Design	Specialist, Designer	1.00	This position is required to address the increases in capital work in regards to PCB Transformer Replacement project.
Increases in Capital Work	RC 314 Transmission Engineering and Specialized Design	Supervisor, Engineering	1.00	This position is needed to manage the 31 Potelco contractors and the upcoming four Service and Design Project Managers (SDPM) and one Lead SDPM for execution of the increases in capital work. This position and the positions reporting to this position will be needed long term to serve both current and future company business needs.
Increases in Capital Work	RC 324 Western Service and Design North	Specialist, Designer	1.00	This position is required to address the increases in capital work. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 369 Engineering Design Services	Specialist, Service and Design Project Manager	7.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work. One of these FTEs will support the Underground Cable program by replacing underground cable and underperforming feeder reconductor. Another will support the delivery of PCB Replacement Program.
Increases in Capital Work	RC 369 Engineering Design Services	Supervisor, Distribution	1.00	A new supervisor position is requested for the Beaverton Service and Design group. The plan is to split the existing group into two departments, which will result in about nine employees per supervisor. Currently the supervisor has 17 reports, which is too large for effective coaching, training, continuous improvement work, and customer outreach. The requested position will be the replacement after the sunset position disappears, allowing us to keep the two supervisor’s long term.
Increases in Capital Work	RC 585 T&D Project Management Operations	Analyst, Business	2.00	Supporting capital construction projects for the increase in capital work.
Increases in Capital Work	RC 585 T&D Project Management Operations	Project Manager	1.00	Planning Engineer for Substation Operations to support increases in capital work.
Increases in Capital Work	RC 585 T&D Project Management Operations	Project Manager, T&D Projects	1.00	No administrative support exists for World Trade Center-centered departments under T&D Asset Management. Departments requiring support are T&D Planning, Project Management, SAM, Geospatial Information Systems, and the organization manager.

Increases in Capital Work	RC 585 T&D Project Management Operations	Specialist, Programs	3.00	Scoping Engineer for Strategic Asset Management (SAM) to support increases in capital work.
Increases in Capital Work	RC 585 T&D Project Management Operations	Specialist, Scheduler	1.00	Scoping Engineer for Strategic Asset Management (SAM) to support increases in capital work.
Increases in Capital Work	RC 592 Strategic Asset Management	Scoping Engineer	2.00	This position will support the following initiatives: Strategic Asset Management, Substation Upgrades/Rebuilds, and Capacity Additions.
Increases in Capital Work	RC 594 Substation Operation Technology	Specialist, Critical Infrastructure Protection	1.00	The Critical Infrastructure Protection (CIP) Specialist is a misnomer. While the job is related to CIP, it is really a Cybersecurity Specialist. Our current CIP specialists who deal with cybersecurity issues are focused on NERC CIP Compliance, which only applies to transmission stations. The majority of capital work is at distribution substations, so we have insufficient resources to support this work. The position will review control and protection designs for the substations to ensure they meet PGE security policy. They will review the CIP Compliance procedures used for transmission to determine the appropriate level of protection for our distribution system.
Increases in Capital Work	RC 594 Substation Operation Technology	Engineer, Electric	3.00	This position is to support the FTEs and processes due to the increases of capital work. Existing resource shortages in Substation Operations have been addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety).
Increases in Capital Work	RC 594 Substation Operation Technology	Engineer, Protection Transmission and Engineering	2.00	A new resource in Substation Operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 594 Substation Operation Technology	Specialist, Operations and Planning Compliance	1.00	A new resource in Substation Operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 594 Substation Operation Technology	Specialist, SCADA Transmission and Engineering	1.00	This position performs testing and energization support for our Supervisory Control and Data Acquisition (SCADA) systems in the field. They help troubleshoot issues found during commissioning and serve as a liaison between the SCADA Technicians doing testing and the Automation Engineers who did the designs. The majority of the capital work is focused on deploying SCADA to Distribution substations, so the amount of SCADA work our team has to support has more than doubled. As such, we are going from one SCADA specialist to two.

Increases in Capital Work	RC 595 T&D Planning	Engineer, Electric	1.00	Position will support additional distribution planning responsibilities related to the increase in capital work. Position will provide insight and analysis that will influence new policies in the changing T&D landscape.
Increases in Capital Work	RC 596 T&D Asset Management	Assistant	1.00	T&D Asset Management has expanded roles and responsibilities in all groups located at World Trade Center. These new roles, along with increasing capital work and initiatives, require transitioning some administrative responsibilities off of managers and individual contributors who have been filling the gap.
Increases in Capital Work	RC 613 Eastside Warehouses	Storeroom	2.00	Increase in resources is driven by increased work volume, due to economy and miscellaneous capital projects. The eastern region storerooms need to support these increased crew levels. For the past year and a half, Storerooms have utilized cross training and temporary hires as a temporary solution. This is not optimal as temporary hires work up to six months before returning to their regular positions.
Increases in Capital Work	RC 614 Westside Warehouses	Storeroom	6.00	Westside Storerooms are understaffed for the volume of crews and work that are currently supported. Storerooms historically have operated on the basis of a 2:1 ratio – two crews can be supported by one Storeroom resource (SR). The current crew SR ratio for Western storerooms is 2.63 which cause jobs to be delayed, crews not leaving on time out of the yard, overtime to be used to get things done, and people burning out.
Increases in Capital Work	RC 615 Southern Warehouses	Storeroom	2.00	Increase in resources is driven by increased work volume, due to economy and miscellaneous capital projects. The eastern region storerooms need to support these increased crew levels. For the past year and a half, Storerooms have utilized cross training and temporary hires as a temporary solution. This is not optimal as temporary hires work up to six months before returning to their regular positions.
Increases in Capital Work	RC 632 Fleet and Garage Operations	Assistant, Fleet and Garage	1.00	Provides centralized procurement and financial controls for Distribution Operations and technical and administrative functions that support cross-functional groups. There are new regulatory requirements for driver and vehicle monitoring. With the continued addition of fleet vehicles requiring licensing and DEQ, the current position can no longer keep up with demand for data entry in systems.
Increases in Capital Work	RC 753 Enterprise Telecommunications	Communication Engineer	4.00	Position designs the communications infrastructure that allows our System Control Center and other centralized functions to get data from our remote facilities via Supervisory Control and Data Acquisition (SCADA), interchange metering and revenue metering. Increases in capital work involve upgrading substations in preparation for Integrated Grid functions, which requires the development of a robust communications infrastructure. Similarly, generation capital work will require additional communication circuits to power plants in support of reliability monitoring and security operations. While the full scope of the IT capital work have not been defined, it is expected that the communications infrastructure for our

				regional facilities and power plants will need to be enhanced to ensure a reliable and secure connection to the corporate network.
Integrated Grid	RC 023 System Control Center Support	Engineer	1.00	Position will perform the functions of a mid or senior level engineer for the development, configuration, maintenance of the Distribution Management System and its integration to control center applications such as Energy Management System and Outage Management System. While the Integrated grid project is shaping up, any such application (e.g. Distribution Automation, Distributed Generation (solar), distributed storage, and other advanced applications) will need to be managed from a central location, as well as integrated into System Control Center processes and systems. Current staffing is not adequate to support any Integrated Grid applications.
Integrated Grid	RC 311 Distribution Engineering	Distribution Engineer	1.00	Position focuses on smart grid deployment and operational planning/model development for the Portland area. As development continues, the need for more accurate day to day, near-term operational models has increased. PGE currently does not have a resource to develop and maintain an accurate power flow model for the Portland area. This resource will allow greater expertise and deployment support for smart grid technology in the Portland area.
Integrated Grid	RC 311 Distribution Engineering	Specialist, Distribution Maintenance	1.00	Position will support the distribution device maintenance program administration, tracking, and reporting. There is also a need to provide additional support to distribution device maintenance data cleanup, maintenance record updates, and reporting and metrics that we don't currently have resources for.
Western EIM	RC 014 T&D Dispatch	System Control Center Outage Coordinator	1.00	Position will be responsible for planning, coordinating, and scheduling transmission line outages with the CAISO, Peak Reliability Coordinator, BPA, and PacifiCorp (Labor in Exhibit 800).
Western EIM	RC 023 System Control Center Support	Energy Management System Engineer	1.00	Position will be responsible for the development, configuration, and full-time maintenance of new Western EIM computer systems and interfaces used by the System Control Center to support Western EIM participation (Labor in Exhibit 800).
Western EIM	RC 593 Transmission and Reliability Service	Analyst, EIM Policy	1.00	Position will be responsible for participating in the formation of regulatory and operational rules that impact the Balancing Authority's ongoing responsibilities in the market (Labor in Exhibit 800)
Western EIM	RC 593 Transmission and Reliability Service	Specialist, Western EIM Settlement and System	2.00	Position(s) will manage the Balancing Authority's ongoing settlement and settlement system responsibilities in the market (Labor in Exhibit 800)

Western EIM	RC 595 T&D Planning	Engineer, Transmission and Operation	1.00	Entry into the Energy Imbalance Market (EIM) requires PGE to maintain an accurate Full Network Model for use in Transmission Operations and by the Energy Imbalance Marketer. PGE's understanding of the NERC Compliance objectives for Transmission Operations, in conjunction with CAISO requirements for EIM participation, continue to evolve and will require additional engineering support beyond the resources currently available (Labor in Exhibit 800).
Total			**169.5**	

2007 - 2016 Actual Level III Storm Damage Losses

CPI	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2007	$ 886,621									
2008	3.8%	$ 5,936,058								
2009	-0.3%	-0.3%	$ 2,106,514							
2010	1.6%	1.6%	1.6%	$ -						
2011	3.1%	3.1%	3.1%	3.1%	$ -					
2012	2.1%	2.1%	2.1%	2.1%	2.1%	$ -				
2013	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	$ -			
2014	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	$ 5,623,875		
2015	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	$ 5,161,601	
2016	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	$4,504,081
2017	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
2018	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
2018$	$ 1,077,545	$ 6,949,217	$ 2,473,977	$ -	$ -	$ -	$ -	$ 5,986,888	$ 5,488,272	$4,728,807

Ten Year Total Level III Storm Damage Losses	$ 26,704,707
Ten Year Avg Level III Storm Damage Losses	$ 2,670,470.67
Average Level III Storm Damage Losses	$ 3,814,958

Year	Level III Storm Actuals	CPI
2004	$ 3,816,404	
2005	$ -	3.37%
2006	$ 4,727,272	3.22%
2007	$ 886,621	2.87%
2008	$ 5,936,058	3.81%
2009	$ 2,106,514	-0.32%
2010	$ -	1.64%
2011	$ -	3.14%
2012	$ -	2.08%
2013	$ -	1.47%
2014	$ 5,623,875	1.61%
2015	$ 5,161,601	0.12%
2016	$ 4,504,081	1.28%
2017		2.54%
2018		2.39%
2019		2.41%
2020		2.48%

	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	$ -	$ (1,289,557)

Summary of Costs Attributable to Level III Storms

Year (a)	Level III Storm Costs[1] (b)	Inflation (c)	$2018 Storm Costs (d)	10-Year Rolling Averages (e)	Annual Reserve Amounts[4] (f)	Potential Reserve Balance by Year, Based on Start of Reserve Treatment[5] Balance = (Previous Balance + Reserve - Actual Costs) 2006 (g)	2007 (h)	2008 (i)	2009 (j)	2010 (k)	2011[6] (l)	2012 (m)	2013 (n)	2014 (o)	2015 (p)	2016 (q)	2017 (r)
1995[2]	10,000,000		16,534,284														
1996[3]	5,880,000	2.95%	9,443,321														
1997	0	2.29%	-														
1998	2,438,440	1.56%	3,769,596														
1999	0	2.21%	-														
2000	0	3.36%	-														
2001	0	2.85%	-														
2002	0	1.58%	-														
2003	0	2.28%	-														
2004	2,976,869	2.66%	3,970,984	3,371,819													
2005	0	3.37%	-	1,718,390													
2006	3,869,486	3.22%	4,837,735	1,257,832	3,371,819	(497,668)											
2007	886,621	2.87%	1,077,545	1,365,586	1,718,390	334,102	831,770										
2008	5,936,058	3.81%	6,949,217	1,683,548	1,257,832	(4,344,124)	(3,846,457)	(4,678,226)									
2009	2,106,514	-0.32%	2,473,977	1,930,946	1,365,586	(5,085,052)	(4,587,384)	(5,419,154)	(740,928)								
2010	0	1.64%	-	1,930,946	1,683,548	(3,401,504)	(2,903,836)	(3,735,606)	942,621	1,683,548							
2011	0	3.14%	-	1,930,946	1,930,946	(1,470,558)	(972,890)	(1,804,660)	2,873,566	3,614,494	1,930,946						
2012	0	2.08%	-	1,930,946	1,930,946	460,388	958,056	126,286	4,804,512	5,545,440	3,861,892	1,930,946					
2013	0	1.47%	-	1,930,946	1,930,946	2,391,334	2,889,001	2,057,232	6,735,458	7,476,386	5,792,838	3,861,892	1,930,946				
2014	5,623,875	1.61%	5,986,888	2,132,536	1,930,946	(1,301,595)	(803,928)	(1,635,697)	3,042,529	3,783,457	2,099,908	168,963	(1,761,983)	(3,692,929)			
2015	5,161,601	0.12%	5,488,272	2,681,363	1,930,946	(4,532,251)	(4,034,583)	(4,866,352)	(188,126)	552,801	(1,130,747)	(3,061,693)	(4,992,638)	(6,923,584)	(3,230,655)		
2016	4,504,081	1.28%	4,728,807	2,670,471	2,132,536	(6,903,795)	(6,406,128)	(7,237,897)	(2,559,671)	(1,818,743)	(3,502,291)	(5,433,237)	(7,364,183)	(9,295,129)	(5,602,200)	(2,371,545)	
2017[7]	4,800,000	2.54%	4,914,873	3,054,203	2,681,363	(9,022,432)	(8,524,764)	(9,356,534)	(4,678,308)	(3,937,380)	(5,620,928)	(7,551,874)	(9,482,820)	(11,413,766)	(7,720,836)	(4,490,181)	(2,118,637)
2018		2.39%			2,670,471												

			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Average of Averages
Average all years	3,051,109	**Average Balances**	(2,781,096)	(2,491,013)	(3,655,061)	1,136,850	2,112,500	490,231	(1,680,834)	(4,334,136)	(7,831,352)	(5,517,897)	(3,430,863)	(2,118,637)	(2,508,442)
Average of years with Level III storms	5,847,958														**Totals**
		Years with Negative Balances	9	8	8	4	2	3	3	4	4	3	2	1	**51**
		Years with Positive Balances	3	3	2	5	6	4	3	1	0	0	0	0	**27**

Notes
[1] Does not include storm reclass to capital or T&D insurance proceeds.
[2] December 12, 1995 wind and ice storm. Restoration costs in excess of $10 million
[3] December 26, 1996 ice storm.
[4] Assumes a minimum 2-year lag from when actuals occur until they can be incorporated into a general rate case
[5] Assumes annual update of reserve accrual
[6] Beginning of storm reserve deferral based on Commission order No. 10-478
[7] Year to date with very preliminary estimate for January 10/11 storm

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Customer Services & CET

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Kristin Stathis
Carol Dillin

February 28, 2017

Table of Contents

I. Introduction

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

A. My name is Kristin Stathis. I am Vice President of Customer Service Operations.

My name is Carol Dillin. I am Vice President of Customer Strategies and Business Development.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. We explain PGE's forecast of Customer Service operations and maintenance (O&M) costs[1] for the 2018 test year and compare them to 2016, which represents PGE's most recent actual results. We also discuss initiatives that support improving the customer experience through:

- Increasing operational efficiency and effectiveness;
- Meeting customer needs through technological improvements in how we serve them;
- Providing self-service options[2] targeted to meet our customers' needs and expectations; and
- Improving business processes for billing and enhanced customer channels.[3]

Q. Please describe the functions of PGE's Customer Service organization.

A. Our Customer Service functions support direct operations of smart meters, billing, payment processing, collections, and responding to customers. The last category entails responding in a timely, courteous, and professional manner to customer requests received through

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[1] PGE's Customer Service costs are consistent with FERC Chart of Accounts categories Customer Accounts Expenses and Customer Service and Informational Expenses (i.e., accounts 901-910).
[2] "Self-service" refers to a customer's ability to conduct a transaction on his or her own, without needing to speak to a company representative.
[3] "Customer channel" refers to a method of customer interaction chosen by customers based on what services are available through that channel. Internet, Interactive Voice Response, mobile platform, and community offices are examples of distinct customer channels for payment.

various channels such as the contact center, community offices, mail (postal or e-mail), mobile platform, Interactive Voice Response (IVR),[4] and by working directly with customers in their homes and/or places of business. Within Customer Service, we classify strategic activities as those that include: 1) researching and collecting direct feedback from customers regarding their experiences and expectations; 2) monitoring customer feedback and satisfaction levels; and 3) developing and delivering products and services that best meet customer needs.

Q. How is your testimony organized?

A. In Section II, we provide a brief overview of PGE's Customer Service organization and explain PGE's request for forecasted 2018 costs in comparison to 2016 actual costs. In Section III, we discuss PGE's rate for uncollectible accounts. In Section IV, we provide an update to the Customer Engagement Transformation (CET) program, describing progress since 2014 and our expectations as we complete this project in 2018. In that section, we also discuss CET costs, including total capital costs, and the deferral mechanism for program development costs. We provide concluding remarks in Section V and our qualifications are summarized in Section VI.

[4] IVR refers to a call center technology that allows customers to use touch-tone telephones to interact with computer systems.

II. Customer Service Overview

A. Goals

Q. Please describe PGE's goals for the Customer Service organization.

A. The Customer Service organization's primary goal is to deliver value to our customers by ensuring that we provide outstanding customer service at a reasonable cost. In addition to providing timely and accurate customer usage data plus effective metering, billing, collection, and response services to all customers, PGE is focused on improving the value it delivers through operational quality. PGE has implemented projects that improve service, increase efficiency, and provide benefits and convenience to customers in how they interact with us. Customer value is achieved by PGE investing in our employees and culture of continuous improvement, evaluating and deploying new technologies that support business and customer needs, and delivering innovative programs and solutions that benefit customers.

Q. How does PGE determine whether it is achieving its goals for Customer Service?

A. PGE determines whether it is achieving its goals primarily by evaluating feedback gathered directly from its customers. Feedback from residential and business customers is gathered in a variety of ways including: quarterly, semi-annual, and annual customer satisfaction surveys; on-going surveys on customer transactions with PGE that are completed on the phone or our website; and occasional customer focus groups on specific topics. This feedback is used to improve PGE's service and identify customer interest in new programs and service options.

Q. What is PGE doing to respond to the feedback it receives from customers?

A. As noted above, PGE has implemented projects that improve service, increase efficiency, and provide benefits and convenience to customers in how they interact with PGE such as paperless billing and automated web-enabled 'customer move' service requests (discussed in Docket No. UE 283).

Since PGE's most recent rate case, Docket No. UE 294, we have been focused primarily on CET work, discussed further in Section IV, and implementation of demand response pilots identified in PGE's Smart Grid Report and Integrated Resource Plan. Customer feedback continues to be used to inform our decisions related to products and services as well as business processes. Other improvement initiatives, outside of the CET program, are considered on a case-by-case basis and prioritized against the overall CET effort.

B. O&M Costs

Q. What are PGE's forecasted Customer Service costs for the 2018 test year?

A. PGE forecasts approximately $75.3 million in Customer Service O&M for 2018, excluding uncollectible expenses, which are a revenue sensitive cost. This represents a $9.8 million increase relative to PGE's 2016 actual costs. The overall increase to Customer Service is attributed primarily to cost escalation, new or expanded programs (such as energy storage), and charges/allocations for Information Technology (IT). Table 1 summarizes these costs and they are discussed in more detail below.

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

Category	2016 Actuals	2018 Forecast	Delta (2018-2016)*
Labor (excluding CET)	$28.9	$32.1	$3.2
Non-Labor (excluding CET)	$14.8	$16.7	$1.9
Subtotal*	**$43.7**	**$48.8**	**$5.1**
CET Program Costs	$4.5	$1.4	($3.1)
IT Costs	$17.3	$25.1	$7.8
Subtotal*	**$65.5**	**$75.3**	**$9.8**
Uncollectibles	$5.2	$7.0	$1.8
Total Base Business Costs*	**$70.6**	**$82.3**	**$11.6**
FTEs	**448**	**454**	**6.0**

* May not sum due to rounding

Q. Please explain the forecasted increase in costs from 2016 to 2018.

A. In addition to cost escalation, the primary increase in Customer Service non-labor costs from 2016 to 2018 is a function of outside services to support research, program development, and program design in relation to: energy storage, electric vehicles, distributed generation, other emerging technologies, and demand response programs.

Q. What accounts for the increase in labor costs from 2016 to 2018?

A. The primary driver is wage and salary escalation, which is discussed in detail in PGE Exhibit 400. There is a small increase in full time equivalent employees (FTEs) that is due to customer growth, which has increased significantly in the recent past. PGE Exhibits 800, and 1200, discuss customer growth in more detail.

Q. Do you address IT costs in this testimony?

A. No. Because IT costs are charged or allocated to all operating areas of the company, they are discussed in detail in PGE Exhibit 500.

III. Write-offs of Uncollectible Accounts

Q. What is the current allowed Uncollectible Rate for 2016?

A. PGE's current approved uncollectible rate is 0.4032% of light and power retail revenue based on PGE's UE 294 general rate case.

Q. What uncollectibles rate does PGE propose for 2018, and how did PGE arrive at that rate?

A. PGE proposes a 0.370% uncollectibles rate for 2018 light and power; a reduction of 0.0332% from the currently approved rate. This rate is based on a five-year average of actual write-offs (i.e., 2012–2016).

Q. Why is PGE using a five-year average?

A**.** A five-year average better reflects economic cycles and normalizes significant one-time positive or negative events such as the planned suspension of some credit and collection activities for part of 2018.

Q. Why would you suspend credit and collection activities for part of 2018?

A. The reason is that PGE is planning to go live with the new Customer Information System in the second quarter of 2018 (discussed in Section IV, below) and limiting credit and collection activities is a standard practice when implementing a new CIS. For example, we may choose not to disconnect customers during a portion of the system go-live and stabilization period, and may suspend late notices and/or credit reminder calls, in part to minimize calls to the Contact Center, also described in Section IV, below. This logically may result in a higher actual uncollectible rate in 2018 than would otherwise occur. Therefore, using the five-year average normalizes that significant one-time event.

IV. Customer Engagement Transformation (CET)

A. Overview

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

A. CET is a comprehensive multiyear program (i.e., 2014 to 2018) comprised of 24 projects focused on operational efficiencies, process improvements, employee development, business strategies, customer strategies, and the replacement of two large customer systems:

- Customer Information System (CIS); and
- Meter Data Management System (MDMS).

We refer to the effort to replace the CIS and MDMS as the Customer Touchpoints project, and this replacement effort is the CET program's focus and sole project for 2017 and 2018.

Q. Why are you replacing these systems?

A. Our current systems (installed 15 years ago) are so outdated that they are no longer supported by the product vendors, are difficult and costly to maintain, and are inadequate for efficient customer service. Replacement is critical to maintaining operations because the cost to maintain the old systems and risk associated with them increase the longer we wait. In conjunction with replacing these systems, we are taking advantage of opportunities to make improvements such as implementing more efficient billing through automation and improving key business processes that have an impact on customer experience.

The additional functionality of the new systems will provide PGE with opportunities to improve the way we engage and serve our customers. We discussed CET in detail in our last three general rate cases (UE 262, PGE Exhibit 900, Section III; UE 283, PGE Exhibit 1000, Section IV; and UE 294, Exhibit 900, Section III).

Q. Has the CET timeline and/or roadmap changed since PGE's last general rate case?

A. Yes. PGE recognized the need to revise the schedule for the CIS/MDMS replacement projects and moved their start date from April 2015 to January 2016. As a result, the expected completion date was moved from the second quarter of 2017 to the second quarter of 2018. The revised CET roadmap is provided in PGE Exhibit 901.

Q. Why was this change necessary?

A. It was necessary to adjust the CET schedule for several reasons:

1. An overlap in work groups and resources needed for both CET and PGE's Wave 2 project.[5]
2. Employees needed time to adjust to the new system processes initiated by Wave 2 systems (i.e., Maximo and Field Manager/Scheduler, Geographic Information System/Graphic Work Design and Outage Management System).
3. Feedback from employees signaled the need for a moderated pace of change within PGE.

B. Implementation

Q. What CET activities have you implemented to date?

A. PGE completed several operational efficiency projects under CET prior to the start of Customer Touchpoints:

- Contact Center Improvement – Helped reduce average call handling time, improved the effectiveness of forecasting and scheduling processes, and freed up capacity that can be redeployed toward improving service levels.

[5] The Wave 2 project (i.e., the transmission and distribution portion of the 2020 Vision initiative) was discussed in PGE's previous three general rate cases: PGE Exhibit 800, UE 262; PGE Exhibit 900, UE 283; PGE Exhibit 800, UE 294.

- Billing and Credit – Simplified reports in Billing and Credit reduced nearly 12,000 monthly bill reviews.
- Paperless Bill – Focused effort on increasing paperless bill enrollment, increasing participation to 27.1%.
- Knowledge Management – Provides a standardized, searchable, single-source knowledge management system so customer service employees can quickly access information they need to serve customers.
- Quality Customer Interactions – Improves the quality of interactions between Customer Service Operations (CSO) employees and customers by improving the process for receiving customer feedback and standardizing CSO's Quality Assurance and performance programs.
- Workforce Management – Improves the effectiveness of workload forecasting and optimizing employee schedules throughout CSO, freeing up capacity that can be applied toward improving service levels or reducing costs.
- People Development for CSO – Identifies and develops new skills to build workforce capabilities for the future, enable CSO to adopt new systems and processes, and continue to improve customer service and operational efficiencies.

Q. What have you completed to date in the Customer Touchpoints project?

A. The Customer Touchpoints project achieved several milestones, including:

- Completed licensing of Oracle's Customer Care and Billing (CC&B) and meter data management solutions, along with seven other Oracle modules for the meter-to-cash and customer service and support functions of the business. This integrated technology solution will replace PGE's existing CIS and meter data consolidator systems and approximately 50 other applications and databases currently in use.

CC&B and associated Oracle modules will introduce new capabilities to help us serve customers in new and more effective ways, enabled by underlying process improvements and automation, such as automated billing of net metering.

- Automated the building, deployment and testing of applications and infrastructure. IT build automation saves time, standardizes processes, improves the consistency and quality of application and database builds, reduces manual steps that introduce costly errors, and frees administrators to focus on higher-value tasks.
- Implemented iterative design and build cycles. The technology is continuously delivered across three cycles of building new functionality and testing future-state processes in the system. Currently, the project has completed two of the three cycles and the system can print a bill for several residential rate schedules, going from meter-read to bill.
- Conducted data cleansing, data conversion and initial configuration. Cleaning and converting sets of PGE basic residential customer data from our existing CIS into a base version of the new technology, as well as performing initial configuration, minimizes project risks and helps ensure that the end-product meets business needs. Demonstrating a working version of the new technology as the project proceeds through its series of iterative design and development cycles enables the project team and subject matter experts from the business to see how the new system will work. It also permits the team to test successively more complex components of the systems.

Q. What is CET's focus in 2017 and 2018?

A. In 2017, the CET program will complete the third and final design/build/test cycle. The focus will then shift to end-to-end testing and finally implementation. Key CET activities in 2017 and 2018 are: 1) system design, hardware installation, software implementation and testing; 2) training employees to work with the new systems and business processes; and 3) deployment and stabilization.

1. <u>System design, hardware installation, software implementation and testing:</u>
   - Complete system-design requirements, with hardware and software installed.
   - Ensure that data and process-integrity remain intact through rigorous system build-out and testing.
   - Continue testing the new systems by completing "dry-runs" or practice "go-lives" to validate system stability and performance.
2. <u>Employee training and preparedness for the adoption of new processes and systems</u>:
   - Continue to support employee adoption of new processes and systems by designing and delivering various training activities, providing opportunities for employees to practice using the new system, and supporting leadership as they guide the workforce through these changes.
3. <u>Deployment and stabilization</u>:
   - In 2017, we will finalize the build-out of the new CIS and MDMS. Beginning in the middle of the year, we will conduct end-to-end testing to ensure that all business processes work as designed, and that bills can be produced accurately and timely.
   - Also starting in 2017, we will set the baseline metrics and service levels for all groups that will be using the new CIS and MDMS. During the testing phase, we will determine how these metrics will adjust with the new processes and systems. Ultimately, these metrics will help us determine that the systems have been stabilized and we are back to "normal" business.

Q. In Section III, you mentioned suspending certain collection activities during the system go-live and stabilization period. Are you suspending any other activities due to CET implementation?

A. Yes. We plan to suspend some collection and credit activities, non-critical meter exchanges, and other non-critical activities. The reasons for suspending these include:

- Reducing customer phone calls as employees are first learning the new system. Because average call handle-times are expected to increase at first, reducing call volumes can help manage wait times.[6] We expect the revenue and collections suspension to reduce the number of collection and reconnect calls.
- Reducing non-critical work in the system as the project team fine-tunes the system. Suspending price-changes during stabilization will eliminate an unknown variable from the system and allow data-comparison that will enable better testing of the data.
- We will increase meter and service-order work prior to go-live so that only critical customer-requested meter or service order work will need to be completed after deployment, as employees are learning to use new systems.

C. Benefits

Q. Please describe benefits this program will provide.

A. The implementation of new systems will provide several enhancements that are responsive to customer needs, including the ability for customers to:

- Make one-time check payments over the phone; currently customers are redirected to the IVR system or the PGE website to make the payment.

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[6] Customer wait times in PGE's call center are the result of how many calls we receive and how long they take to process.

- Enroll in Auto Pay or update bank account information over the phone.
- Choose the specific date their bill will be due, instead of the bill cycle (date range), helping customers better plan and manage their cash flow.
- Enroll in the Preferred Due Date program with fewer restrictions making it more accessible to customers who could benefit the most.
- Keep their new account number permanently (when new systems are implemented), even when they move to a different address within PGE's service territory.

Finally, the new CIS will support more varied pricing options compared to what is available with our current system.

D. Costs

Q. What is the total cost of the CET program?

A. The total cost of the CET program is currently estimated to be $140.0 million in capital and $27.5 million in program development O&M costs. Of the total capital cost, projects representing approximately $128.0 million will become operational in 2018. This amount represents the main components of the Customer Touchpoints project. PGE Exhibit 902 provides the amounts of capital that close to plant (i.e., become operational) by year.

Q. Are the 2018 CET capital costs included in PGE's proposed prices effective January 1, 2018?

A. No. Because PGE has set rate base as of December 31, 2017, and the largest components of CET capital (i.e., CIS and MDMS) go live in 2018, they are not part of the prices that will go into effect on January 1, 2018. As noted in PGE Exhibit 200, Section VI, PGE is using year-end 2017 rate base to preclude assets that are not in service prior to January 1, 2018, when prices go into effect. PGE also excludes the associated 2018 depreciation and amortization to be consistent with normalization rules in the Internal Revenue Code, Section

168(i)(9), as described in PGE Exhibit 200, Section III. PGE will propose cost recovery for the 2018 CET costs in a future proceeding.

Q. Are CET program development O&M costs included in PGE's proposed prices effective January 1, 2018?

A. Yes. CET program development O&M costs are being incurred from 2014 through 2018 and are part of deferral and amortization mechanisms that have been previously, and are currently, included in base rates.

Q. How, specifically, are you treating the program development O&M costs?

A. In our three previous general rate cases, CET O&M costs were treated as a regulatory asset and set to be amortized over the remaining development life of the project, ending in 2018. The result of this mechanism was that:

- 2014-2016 CET O&M costs have three vintages of amortization as reflected in PGE Exhibit 903; and
- The regulatory asset and amortization costs were included in base prices in each rate case from 2014 through 2016 (i.e., 2014, UE 262; 2015, UE 283; and 2016, UE 294).

Because PGE did not file a 2017 general rate case, the 2017 CET program development O&M costs were deferred separately by Commission Order No. 16-487 (Docket No. UM 1796).

Q. How are you proposing to treat the program development O&M costs in the 2018 general rate case?

A. The original intent of the CET deferral mechanism was for all vintages to be amortized over the remaining period of CET development, which would end in 2018. Based on this, and reflected in PGE Exhibit 903, PGE would amortize approximately $8.0 million in 2018, either in base rates or through a supplemental schedule. As summarized in PGE Exhibit

903, the $8.0 million consists of the final year of amortization for the 2014-2016 deferral vintages plus the 2018 CET program development O&M. Because the 2017 deferral was created in a non-rate case proceeding, we expected that vintage to be amortized separately.

Q. Does PGE Exhibit 903 represent your current proposal?

A. No. We believe that a better and more meaningful approach would be to amortize all remaining CET program development O&M over ten years beginning in 2018. This would have the additional effect of lowering the price impact in 2018 from approximately $8.0 million to $1.4 million, and would include the 2017 deferral. Consequently, as part of this filing, we request that the Commission issue an accounting order authorizing the following with respect to CET program development O&M:

- The 2018 costs to be booked to a regulatory asset and included in rate base, as applicable, along with all remaining balances from prior CET deferral vintages (similar to 2014-2016 CET deferral treatment); and
- The remaining balance of all the 2014-2018 deferrals to be amortized in base prices over ten years beginning in 2018. This proposal is summarized in PGE Exhibit 904.

Q. Does the proposed mechanism include the 2017 vintage deferral?

A. Yes. Our proposal includes the 2017 deferral because it is no different than the 2014-2016 deferrals as included in their respective rate cases. This would allow the entire remaining balance of CET program development O&M to receive consistent treatment while minimizing rate filings and price changes.

V. Conclusion

Q. You stated that PGE's goal for Customer Service is to deliver value to its customers by providing quality service at a reasonable cost. Are the activities planned within your Customer Service organization necessary to achieve this goal?

A. Yes. The projects PGE has completed, the projects currently underway, and the comprehensive plans we have for the future demonstrate PGE's commitment to its customers to operate our business in a smart, efficient, and cost-effective manner, while enhancing and simplifying their experience with PGE.

In order to achieve this goal, we are completing the CET program in 2018 and request the Commission approve the following:

- PGE's forecasted increase in base business costs for Customer Services as described in Section II, part B, above, to be effective January 1, 2018.
- An accounting order authorizing:
  - The 2018 CET program development O&M costs to be booked to a regulatory asset and included in rate base, as applicable, along with all remaining balances from prior CET deferral vintages (similar to 2014-2016 CET deferral treatment); and
  - The remaining balance of all the 2014-2018 deferrals to be amortized in base prices over ten years beginning in 2018.

VI. Qualifications

Q. Ms. Stathis, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Political Science from Willamette University and a post-baccalaureate certificate in accounting from Portland State University. I previously qualified as a certified public accountant in the State of Oregon. I am on the boards of Marylhurst University; the Oregon Alliance of Independent Colleges and Universities; and the Western Energy Institute. I serve as Vice President, Customer Service Operations, at PGE and have been in this role since June 2011. In this position, I am responsible for operational functions including meter services and field operations for meters, smart metering, billing, credit and collections, community offices and the contact center. I began my career with PGE twenty-three years ago as a financial analyst. Since then, I have served in a number of roles including Assistant Treasurer and Manager of Corporate Finance, General Manager of Power Supply Risk Management and General Manager of Revenue Operations.

Q. Ms. Dillin, please describe your qualifications.

A. I received a Bachelor of Arts in Journalism and Spanish from the University of Oregon. I have taken post-graduate business courses at Marylhurst University, and am a graduate of the American Leadership Forum class of 2005. I am on the boards of The Center for Women's Leadership, PGE Foundation, BEST, and the Business Advisory Council for Portland State University. I serve as Vice President, Customer Strategies and Business Development at PGE and have been in this role since June 2011. In this position, I am responsible for the Retail Customer Strategies for PGE. This includes Customer Research and Analysis, Customer Program Development and Management, Retail Technical Strategies, Business Customer Group, Smart Grid, R&D, and Economic Development.

Since beginning my career at PGE twenty-nine years ago, I have served in a number of roles including Public Information Specialist; Director, Corporate Communications and Community Affairs; Vice President, Public Policy; and President of the PGE Foundation.

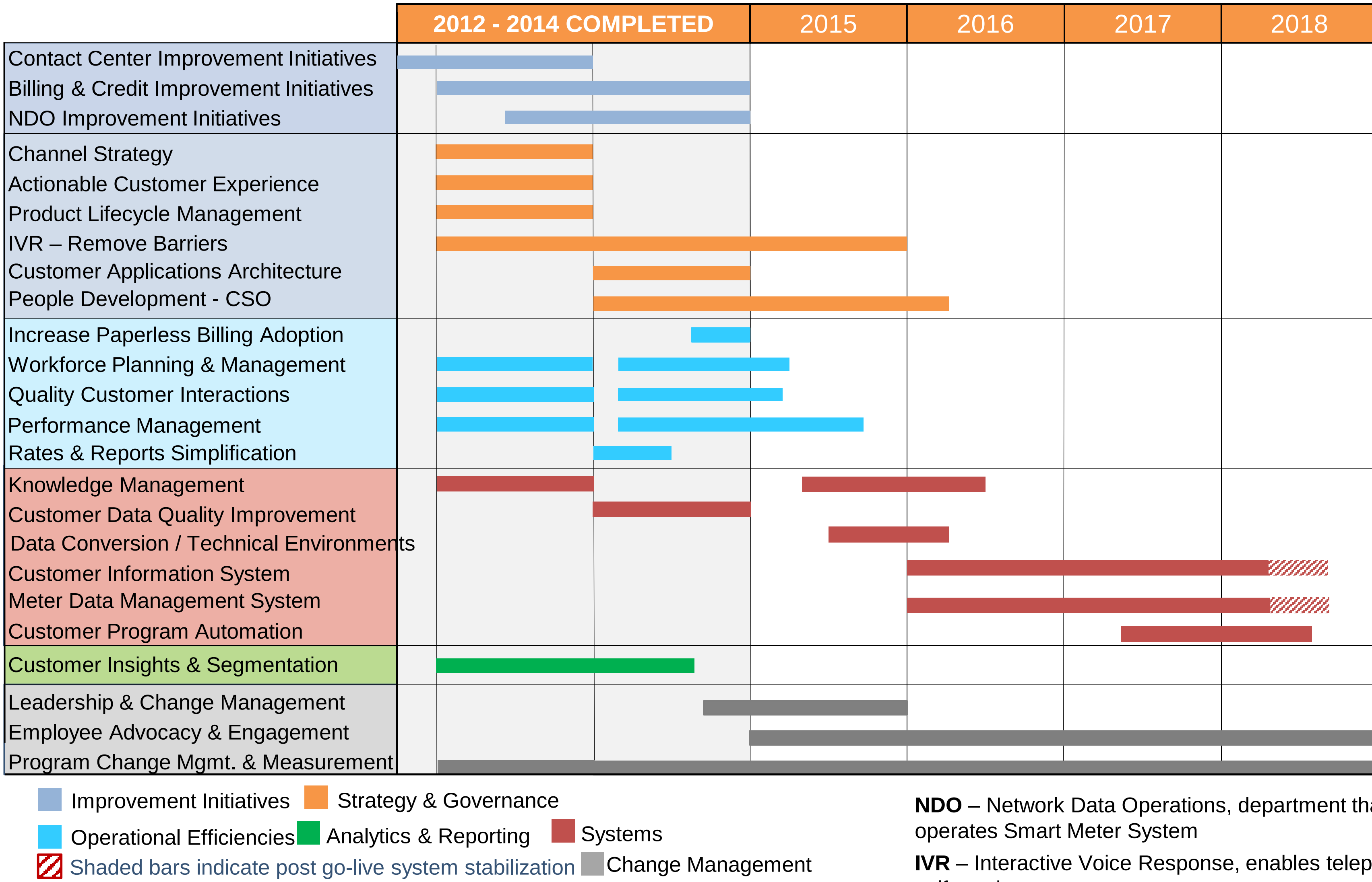
Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
901	CET Roadmap
902	CET Capital Costs by Year
903	CET Program Development Costs with Original Amortization
904	CET Program Development Costs with Proposed Amortization

CET Roadmap



Customer Touchpoints

NDO – Network Data Operations, department that operates Smart Meter System

IVR – Interactive Voice Response, enables telephone self-service

CSO – Customer Service Operations

CS&BD – Customer Service and Business Development

Asset Category	Account	2015 Actuals	2016 Actuals	2017 Forecast	2018 Forecast	Totals
Customer Touchpoints						
software - 10 year amortization	303	$ -	$ 1,908,635	$ -	$ 128,000,000	$ 129,908,635
computer	39102	$ 463,842	$ 1,165,965	$ 5,460,770	$ -	$ 7,090,577
furniture	391	$ 225,498	$ 317,957	$ -	$ -	$ 543,455
		$ 689,340	$ 3,392,557	$ 5,460,770	$ 128,000,000	$ 137,542,667
Other CET						
software - 10 year amortization	303	$ 533,405	$ 1,738,895	$ -	$ -	$ 2,272,300
computer	39102	$ 29,711	$ 188,934	$ -	$ -	$ 218,645
furniture	391	$ -	$ -	$ -	$ -	$ -
		$ 563,116	$ 1,927,829	$ -	$ -	$ 2,490,945
Total CET						
software - 10 year amortization	303	$ 533,405	$ 3,647,530	$ -	$ 128,000,000	$ 132,180,935
computer	39102	$ 493,553	$ 1,354,899	$ 5,460,770	$ -	$ 7,309,222
furniture	391	$ 225,498	$ 317,957	$ -	$ -	$ 543,455
		$ 1,252,456	$ 5,320,386	$ 5,460,770	$ 128,000,000	$ 140,033,612

CET Program Development O&M
Deferral Mechanism
($000)

Line No.	Category	2014[a]	2015[b]	2016[c]	2017[d]	2018	2019
1	**CET Deferrals**	$7,483	$5,754	$4,193	$6,602	$3,465	
	Amortizations						
2	2014 Deferral (UE 262)[a]	$1,600	$1,600	$1,600	$1,600	$1,600	
3	2015 Deferral (UE 283)[b]		$1,330	$1,330	$1,330	$1,330	
4	2016 Deferral (UE 294)[c]			$1,558	$1,558	$1,558	
5	2017 Deferral (UM 1796)[d]				$0	$0	$6,602
6	2018 Costs					$3,465	
7	Adjust 2014-2016 amortization					($566)	
8	Total amortizations by year	$1,600	$2,930	$4,488	$4,488	$7,388	$6,602
9	Rate base deferral balance at year end	$5,883	$8,707	$8,411	$3,923	$0	
10	UM 1796 balance at year end				$6,602	$6,602	$0

Notes:
(a) Approved by Commission Order No. 13-459
(b) Approved by Commission Order No. 14-422
(c) Approved by Commission Order No. 15-356
(d) Deferred by Commission Order 16-487

CET Program Development O&M
Modified/Proposed Deferral Mechanism
($000)

Line No.	Category	2014[a]	2015[b]	2016[c]	2017[d]	2018[e]	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	**CET Deferrals**	$7,483	$5,754	$4,193	$6,602	$3,465									
	Amortizations														
2	2014 Deferral Amortization (UE 262)[a]	$1,600	$1,600	$1,600	$1,600										
3	2015 Deferral Amortization (UE 283)[b]		$1,330	$1,330	$1,330										
4	2016 Deferral Amortization (UE 294)[c]			$1,558	$1,558										
5	2017 Deferral (UM 1796)[d]				$0										
6	2018[e]					$1,399	$1,399	$1,399	$1,399	$1,399	$1,399	$1,399	$1,399	$1,399	$1,399
7	Total amortizations by year	$1,600	$2,930	$4,488	$4,488	$1,399	$1,399	$1,399	$1,399	$1,399	$1,399	$1,399	$1,399	$1,399	$1,399
8	Rate Base deferral balance at year end	$5,883	$8,707	$8,411	$3,923	$12,591	$11,192	$9,793	$8,394	$6,995	$5,596	$4,197	$2,798	$1,399	$0
9	UM 1796 balance at year end				$6,602										

Notes:
(a) Approved by Commission Order No. 13-459
(b) Approved by Commission Order No. 14-422
(c) Approved by Commission Order No. 15-356
(d) Deferred by Commission Order 16-487
(e) Modify CET mechanism to 10 year amortization of all deferral vintages including the 2017 deferral

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Patrick G. Hager
Christopher Liddle

February 28, 2017

Table of Contents

I. Introduction

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

A. My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE. I am responsible for analyzing PGE's cost of capital.

My name is Chris Liddle. I am the Assistant Treasurer and Manager of Corporate Finance and Investor Relations. I am responsible for managing the company's treasury functions including financing as well as investor relations.

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 cost of capital and capital structure for the 2018 test year. PGE's requested cost of capital and capital structure are necessary to maintain its current credit profile for access to the debt and equity markets, to fund its significant capital investments planned for 2018, and to provide PGE the opportunity to earn a fair return for equity shareholders while keeping its costs reasonable. As Dr. Villadsen discusses in her testimony (PGE Exhibit 1100), 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 7.46% cost of capital for the 2018 test year. This cost of capital includes a 9.75% authorized Return on Equity (ROE). Dr. Villadsen has also produced a recommended range for PGE's authorized ROE and 9.75% is below the mid-point of that range. This point estimate is for revenue requirement purposes. Table 1 below shows the

[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)

recommended cost of the two components of PGE's capital, common equity and long-term debt. Table 1 also shows PGE's forecasted 2018 capital structure.

Table 1
PGE's Weighted Cost of Capital
Test Year 2018

Component	Average Outstanding ($000) [1]	Percent of Capital [2]	Component Cost	Weighted Cost
Long-term Debt	$2,661,400	50%	5.170%	2.585%
Common Equity	$2,521,922	50%	9.750%	4.875%
Total	**5,183,322**	**100%**		**7.460%**

[1] "Average Outstanding" reflects PGE's projected average values of long-term debt and common equity for 2018.
[2] "Percent of Capital" reflects PGE's long-term targeted capital structure of 50% debt, 50% equity, and is used to calculate PGE's weighted average cost of capital (Weighted Cost).

Q. How is the remainder of your testimony organized?

A. In the following section, we describe PGE's financial goals and how we manage 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. We discuss PGE's cost of long-term debt, including new and redeemed issuances in Section IV. In Section V, we discuss PGE's capital structure. Section VI provides our qualifications.

II. PGE's Financial Goals

Q. What is PGE's overall financial goal?

A. Our overall goal is to provide adequate capital and liquidity to fund PGE operations at the least cost and least risk to customers. For protection against unforeseen changes in cash flow and to manage daily cash and liquidity needs, we rely on our revolving lines of credit.

Q. Does PGE have additional financial goals?

A. Yes. As part of our overall financial goal, we have additional goals regarding financial performance, counterparty credit risk, and liquidity management, including:

- Solid financial performance:
  - Maintain investment grade credit ratings;
  - Access financial markets at reasonable terms to provide liquidity for operations and capital expenditures;
  - Achieve an actual ROE that is commensurate with the ROE achieved by a group of utilities with similar characteristics, service territory, and business risks;
  - Maintain a capital structure of approximately 50% debt and 50% equity over time;
  - Set retail prices at a level sufficient to recover prudently incurred costs, including an overall return on utility investment, while taking into account the economic conditions of our customers; and
  - Manage counterparty credit risks, wholesale and retail, to protect our customers and PGE.

A. Solid Financial Performance

Q. Why is it important for PGE to maintain an investment grade rating?

A. It is essential for PGE to maintain an investment grade rating in order to secure financing for both debt and equity, at reasonable rates, especially in today's volatile financial environment, and to maintain access to wholesale energy markets. Without an investment grade rating, PGE's access to financing would be more limited, at higher rates, and PGE would have to provide significant additional collateral to its counterparties (and may lose the ability to trade with some counterparties) in the wholesale power market, which would result in higher costs to customers.

Q. How does PGE 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 achieve 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 our financial performance continues to place us within the range of the appropriate financial ratios. We accomplish this through our continuous financial management that includes: closely monitoring our budgets; minimizing our costs to finance operations through the optimal use of revolvers, long-term debt, and equity; closely monitoring our capital structure; and by analyzing our counterparty risks and taking appropriate mitigation measures. Using all of these measures helps us maintain our financial performance levels that are necessary to maintain our investment grade credit ratings.

Q. Financial performance is an important element for the rating agencies. Do they 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 financial measures. We note that in the past, 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 regulation, in general. 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. No. However, PGE did receive two upgrades on its long-term debt from Moody's in the past few years. PGE's long-term debt ratings from Moody's are two notches higher than Standard & Poor's (S&P). These ratings were recently affirmed but PGE continues to take steps to meet S&P's ratings criteria for an upgrade, which would help lower financing costs for customers through lower pricing on revolving lines of credit and new debt.

Q. What does PGE do to ensure an optimal long-term cost of capital?

A. PGE aims to issue long-term debt so that debt maturities closely match investment schedules of our capital projects. We use First Mortgage Bonds (FMBs) as the primary form of debt because it has lower cost than unsecured alternatives. PGE evaluates private placement market rates, bank term loans and delayed draw/forward structures to arrive at the lowest financing costs available to PGE at the time of our 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 the timing and amount of its long-term financing proceeds to meet those requirements. In the past, PGE has used a delayed draw for its long-term bonds that allows us to fix the interest rate on the upcoming bond issue, removing interest rate and funding risk**.**

Q. Does PGE's financial performance help PGE to maintain its desired long-term capital structure?

A. Yes. As we stated earlier, our desired long-term capital structure is 50% equity and 50% long-term debt, although it may fluctuate from year to year. We believe that the 50% equity in our capital structure helps us to better withstand difficult situations, such as under-earning due to events outside of our control. To maintain this ratio, we use several techniques and tools as we discussed above. In addition, we require sufficient retail revenues to maintain the required financial ratios and investor expectations for our long-term capital structure. In the future, we look to continue to use equity issuances, stock repurchases, capital expenditure programs, the debt market, and cash from operations to help us maintain our desired capital structure.

B. Manage Customer and Counterparty Credit Risks

Q. Why is it important for PGE to manage customer credit risks?

A. PGE attempts to minimize its exposure to customer defaults. PGE's energy deliveries and revenues are subject to industry and customer-specific risks and uncertainty, including potential shut down of plants, curtailment of operations, or new capacity as a result of changed economic or specific circumstances. In fact, since the onset of the Great Recession in 2008, a number of our large customers have filed for bankruptcy, liquidated businesses, changed ownership or permanently shut down operations, substantially affecting PGE's actual and anticipated energy deliveries. In particular, in 2015, a large paper manufacturer closed, causing a decline in deliveries. In 2016, operational changes in our solar and metals manufacturing customers caused a further decline in deliveries. Large customer-related energy deliveries and revenue risk is asymmetric, in that through our discussions with our large customers, we are often aware of large expansions and increases to loads in advance to plan for adequate service, but the same notice is not necessarily known or given when customer's energy deliveries significantly decline.

Q. How does PGE manage this customer credit risk?

A. PGE performs credit reviews of our customers and in particular our large customers and associated industries, with high-tech being the most relevant example. Our load forecasters work closely with PGE's Key Customer Managers to gain a better understanding of the business forecasts provided by our customers and their potential consequences on PGE retail load. After our review, we then determine the appropriate deposit required of 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 our large customers. We perform credit reviews of our wholesale power customers, both purchasers and sellers, and then determine the appropriate amount of collateral that we will require from a counterparty based on their credit risk profile. We also set a minimum credit rating below which we will not trade with the counterparty.

C. Liquidity Management

Q. What is PGE's strategy for liquidity management and related revolving credit facility sizing?

A. PGE's strategy is fourfold:

- Carry sufficient credit levels to support both operational and power supply needs over a five year forward looking time horizon.
- Achieve designation of adequate or better from rating agencies (based on Moody's and S&P's interpretation of our liquidity).
- 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 pricing is right.
- Manage market exposure related to maturing lines of credit by replacing lines 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. The separation has allowed 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 you last perform such an analysis?

A. We last analyzed our revolving lines of credit requirements in the fall of 2016.

Q. What were the results of your fall 2016 analysis?

A. Based on our 2016 analysis, we determined that PGE's current revolver of $500 million is sufficient to meet our liquidity needs in support of power supply and other operations. We will monitor the need to increase the revolver in 2018 based on the outcome of the Integrated Resource Planning process and subsequent competitive bidding process.

Q. Did you determine if the results of your analyses would affect PGE's ratings by Moody's and/or S&P?

A. Yes. For Moody's criteria, our analysis found that our liquidity profile would be rated "adequate" in 2017 and 2018. For S&P, we would be rated "strong" in 2017 and would be rated "adequate" in 2018 based on their rating criteria. Based on this set of analyses, we determined that our current revolver capacity of $500 million is sufficient at this time.

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 debt are A3 and BBB. PGE's credit ratings, which were recently affirmed, are provided in PGE Exhibit 1002.

Q. You noted above that rating agencies consider a 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" (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%).[3] S&P indicates that "[r]egulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness."[4] 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 ability for timely recovery of prudently incurred costs.

Q. Have financial analysts or rating agencies noted any concerns regarding regulatory outcomes as they pertain to PGE?

[3] "Rating Methodology – Regulated Electric and Gas Utilities." Moody's Investor Service- December 23, 2013.
[4] "Key Credit Factors for the Regulated Utilities Industry." Standard & Poor's- November 19, 2013.

A. Yes. Both Moody's and S&P have expressed some concern regarding the recovery of PGE's capital costs for Carty.[5] They expect that the increased costs for Carty will be recovered either through the litigation proceedings occurring between PGE, the Carty construction contractor, and two sureties who provided a performance bond on the project, or through retail rates.

Q. Do financial analysts have additional concerns regarding regulatory outcomes for PGE?

A. Yes. Sell side analysts have noted that the Public Utility Commission of Oregon (OPUC) has historically allowed ROEs that are slightly below the national average, but they also note that recent settlements have included constructive outcomes such as timely rate recognition of investment, forward looking test years, revenue decoupling, and a renewable adjustment clause.[6] In the past, the rating agencies have stated concerns regarding the asymmetric nature and size of the deadbands in the PCAM, and it has been an ongoing concern expressed by financial analysts.

Q. What concerns have financial analysts expressed regarding the PCAM?

A. Most electric utilities tend to have a 'pass through' of their power costs if a PCAM is in place, with no deadbands. PGE's asymmetrical deadband is unique. Thus, it is not unexpected that analysts' concerns surround the wide deadband and the asymmetry of benefits allocation, which could result in "meaningful" impacts on PGE's earnings, increasing volatility. Wells Fargo mentions the following risks for PGE: negative regulatory developments; Request For Proposal outcome uncertainty; and risks related to the

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[5] "Portland General Electric", Credit Opinion, Moody's Investment Service, July 8, 2016
"Portland General Electric", RatingsDirect, S&P Global Ratings, June 23, 2016
[6] "POR Maintained Guidance; IRP Pending - Hold." Gabelli & Company- October 31, 2016.

asymmetrical PCAM (hydro, plant outages, etc.).[7] J.P. Morgan lists PGE fuel and purchased power recovery mechanism as a source of risk: "any combination of a reduction in hydro conditions or an increase in the price of coal or natural gas could adversely impact POR's near-term earnings."[8] Key Banc views the PCAM as a source of "earnings variability related to fuel price volatility" and has stated that "[a]ny opportunity to make changes to this mechanism to reduce earnings risk around fuel would be viewed positively."[9]

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. This is because investors and creditors require greater compensation for owning an investment with more risk. 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 increasing the cost to finance PGE activities.

B. Update of Financial and Accounting Regulation Changes

Q. How have financial sector regulations changed?

A. Following the financial crisis, policymakers and regulators have sought to impose tougher rules and standards on banks in hopes of preventing future systemic crises. Regulatory efforts have been primarily focused in the following four areas: higher capital requirements (including higher minimum ratios and higher quality capital); new liquidity standards (new ratios and requirement for higher quality liquid assets); assigning higher capital

[7] "POR: CapEx Comes Through On Q3 Update" -Wells Fargo Equity Research- 28 October 2016
[8] "U.S. Utilities & Power Outlook."-J.P.Morgan-16 December 2016
[9] "Utilities – ALERT: Edison Electric Institute." –Key Banc Capital Markets- 8 November 2016

requirements and increasing supervision for the largest financial institutions (Systemically Important Banks); complying with money market reforms (causing a significant shift from prime fund to government funds and impacting yields); and adopting national initiatives (Dodd-Frank and Volker rule).

Q. How did commercial banks meet these new requirements?

A. First, the banks began tightening of lending standards during 2012, making it more difficult for firms to access credit, potentially increasing firms' costs to obtain credit. Second, banks were forced to participate in the liquidity scenarios outlined by central banks around the world, encouraging many banks to maintain more reserves on hand than they had historically. One additional result is that U.S. banks have significant excess reserves at the Federal Reserve Bank (Fed),[10] leaving less available for lending.

Q. Have these new requirements affected PGE's ability to access funds?

A. PGE has yet to see a significant impact due to these requirements. In 2015, we saw some financial stress passed through to PGE and other utilities as banks complied with the Basel III regulation (full compliance is required by 2019). However, we have yet to experience the notable increase in borrowing costs we expected to result due to this stress. Banks have chosen to be more particular when lending funds and, therefore, the availability of credit has tightened for certain entities.

Q. What challenges does PGE face in connection to 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 from long-term power purchase agreements (PPAs). S&P believes that because of

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[10] http://research.stlouisfed.org/fred2/series/EXCSRESNS.

these quasi-debt instruments an adjustment must be made to the capital structure to reflect the additional leverage of PPA contracts. Significant increases in the debt ratio are a quantitative trigger for potential ratings downgrades. A ratings downgrade by S&P from PGE's current rating 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.

Q. What challenges does PGE face in connection with Financial Accounting Standards Board Accounting Standards?

A. Accounting Standards Codification (ASC) 810 Consolidation of Variable Interest Entities (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 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, 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. Although PGE is not involved in the creation of these entities and has no equity or debt invested, we may be required to consolidate the financial results of PPA counterparties with our own. The counterparty entities are expected to be highly debt-leveraged and consolidating their capital structure will likely distort PGE's authorized capital structure. High debt leverage will impact PGE's creditworthiness, as the increase in PGE's debt-to-equity percentage increases financial risk. To support PGE's creditworthiness and realign its capital structure, an increase to PGE's common equity could be necessary to offset the impact of the additional debt, consolidated under ASC 810.

Q. Has the Financial Accounting Standards Board revised or added Accounting Standards that could impact PGE?

A. Yes. In February 2016, ASC 842 Leases was updated by the Financial Accounting Standards Board. The new standard will require operating leases to be recorded on a company's balance sheet as a right of use asset with a corresponding lease liability. On the income statement, capital lease assets will be amortized and recorded within applicable depreciation and amortization periods, and the minimum lease payments will be split between principal and implied interest, which will be recorded as interest expense. Operating leases will record amortization and interest expense as one straight-line value within operating expense on the income statement. PGE is in the process of quantifying the impacts of the new lease standard and plans to adopt the standard no earlier than its effective date of January 1, 2019. In light of our earlier discussion on imputed debt, PGE continues to have discussions with S&P as well as Moody's regarding their expected treatment of these changes for ratings purposes; however, nothing definitive is available yet.

C. Macroeconomic Uncertainty

Q. One factor that can certainly affect bond ratings is the economy, as earnings are partially driven by economic growth. Can you provide a brief overview of the recent years' market conditions and going forward?

A. Yes. First, we should expect some uncertainty in financial markets due to the change in the U.S. presidential administration and the expected changes in fiscal and monetary policy direction. Second, the U.S. economy has become more integrated into the world economy over time. Thus, developments in other parts of the world can affect the U.S. economy and require additional awareness of these developments. In addition, most developed countries continue to grapple with the challenge of taking appropriate fiscal and monetary policy actions in the aftermath of the financial crisis, with several central banks pursuing *negative* interest rates. Of significant concern is the euro zone. The euro zone grew slightly in the first quarter of 2016, but the growth slowed in the second half of the year. The lack of growth in the euro zone can impact the U.S. economy as the demand for its exports will decline, due to lower income in the euro zone as well as the strengthening dollar. Of particular concern in the euro zone are:

- Britain's 2016 vote to exit the European Union (EU), or 'Brexit'. The separation of Britain from the Common Market will have significant impacts on the financial markets, although no one is quite certain what those impacts will be. For example, London is the center for much of the European financial industry and if Britain departs from the EU, then that financing may migrate to Frankfurt or another EU financial center. Also, trade between Britain and the EU (and between Ireland and Britain) is likely to be disrupted as the EU imposes tariffs or other trade measures until a trade agreement is negotiated. The euro and the pound are both likely to be impacted and the dollar is likely to strengthen as investors seek stability.

- The continuing political development in Greece. Greece elected a government that pledged to cancel the austerity program imposed by outside financial entities in exchange for additional lending to Greece. The current government continues to negotiate with international lenders and to pursue no additional austerity measures. This situation will likely continue in 2017 and beyond and will continue to have an impact on the financial markets.
- The Italian banking crisis. Italy's banks are being weighed down by several hundred billion dollars in bad loans, which they are having difficulty divesting. They are also struggling with basic profitability as Italy's economy is at a standstill and not expected to grow more than 1% in the coming years. Failure of Italy's banks could result in negative financial consequences across Europe with potential effects on global markets.

Another macroeconomic factor that needs to be considered is the expected rise of interest rates. The Fed ended its quantitative easing in 2014 and has raised rates twice within the last 14 months. The most recent increase of a quarter of a percentage point occurred in December 2016, and the Fed has forecasted three quarter-point increases in 2017 with the stated caveat that the impact of new economic policies could alter future decisions.[11]

Q. Do potential risks remain in the U.S. or global economies?

[11] "Fed Raises Rates for First Time in 2016, Anticipates 3 Increases in 2017" The Wall Street Journal, 15 December 2016
http://www.wsj.com/articles/fed-raises-rates-for-first-time-in-2016-anticipates-3-increases-in-2017-1481742086

A. Yes. Rating downgrades or deteriorating credit quality of a country may result in a decline in the value of government bonds held by banks, triggering losses. Where the securities are used as surety for funding or derivatives, banks face calls for additional collateral, draining liquidity from markets.

Banks may be forced to hedge their credit value adjustments - adjustments made to account for the credit risk of counterparties. This hedging is usually done by purchasing default protection on sovereign entities or shorting government bonds. This will exacerbate losses as sovereign entities' bond values fall further.

Market constraints may necessitate use of proxies for sovereign entities, including shorting or buying insurance on equity indices or major stocks. Banks may short sell the currency as a de facto hedge. Proxy hedges transmit the volatility into other asset markets. This creates additional risk as volatility spikes sharply and correlation between major asset classes becomes unstable, especially in a risk-on risk-off trading environment.

IV. Cost of Long-Term Debt

Q. How did you calculate the cost of long-term debt for 2018?

A. PGE Exhibit 1001 presents the amount and the effective cost of PGE's outstanding long-term debt for the test year. This includes existing bond issuances as of January 15, 2016, as well as bond issuances and retirements expected in 2017 and 2018. We included the applicable adjustments to debt as approved in OPUC Order No. 07-015 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 test year 2018.

Table 2
PGE's Cost of Long-Term Debt ($000)

	2018 Forecast	**UE 294* Order No. 15-356**	**Difference**
Principal Amount	$ 2,661,400	$ 2,344,400	$ 317,000
Annual Interest Cost	$ 137,603	$ 125,443	$ 12,160
Effective Interest Rate	**5.170%**	**5.350%**	**(0.180)%**

** UE 294 figures include amounts from long-term debt issued in January 2016.*

Q. What future debt issuances did you include in your analysis?

A. We expect to issue $450 million in long-term fixed rate debt during 2017, and have included the full amount in our calculation as our current best estimate. At this time, we do not anticipate the need to issue long-term debt in 2018. We will provide an update to our cost of long-term debt in our rebuttal testimony, which will include changes in long-term debt for 2018, if any.

Q. What is the expected term, coupon rate, and issuance cost for the bonds to be issued in 2017?

A. PGE currently expects to issue three 30-year tranches of FMBs in 2017 with an estimated coupon rate of 4.24%. The first tranche is expected to be issued early in the year, and the second two tranches are expected to be issued late in 2017. We will update our cost of debt as actual terms become available.

Q. How were 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 any long-term PGE debt maturing in 2017 or 2018?

A. Yes. PGE has $150 million of term loans maturing in November 2017. At present, there are no maturities in 2018.

V. Capital Structure

Q. How did you determine the appropriate capital structure for 2018?

A. We evaluated PGE's capital structure using the forecasted income statement and balance sheet for 2018. Additionally, we considered several factors, including PGE's need to maintain its financial strength; flexibility and adequate liquidity; its ability to maintain reliable and economical access to the capital markets; minimizing the cost of capital to customers and shareholders; and the Commission's Order in UE 294 (Order No. 15-356). We also considered PGE's desire to maintain a capital structure consisting of 50% long-term debt and 50% equity.

Q. Does PGE expect to issue common equity in 2018?

A. No. At this time PGE does not anticipate additional equity issuances but we will provide an update if our financing plans change**.**

Q. Are you seeking a different capital structure than that in UE 294?

A. No. In UE 294, Order No. 15-356 adopted a settlement among the parties that reaffirmed PGE's regulated capital structure at 50% equity and 50% debt. PGE's long-term goal continues to be to maintain our 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 intend to maintain 50% equity in its capital structure?

A. It is the optimal debt-to-equity ratio for PGE because it offers a balance between the ideal debt-to-equity range and reduces our cost of capital. The equity portion of PGE's capital structure is important because it represents how PGE finances its cash needs. In addition, the equity portion helps offset the leverage and risk that PGE encounters, in part, as it has finished its large capital expenditure program. It is also required to help offset the leverage imputed by the rating agencies due to purchased power. In light of ASC 810 (discussed above), understanding and mitigating the leverage created by imputed debt is also important. Additionally, PGE faces risks in today's banking environment because of its small size, and it must maintain a solid capital structure and financial flexibility to help contain customer costs and retain shareholder value.

Q. Aside from the risks discussed above, what other types of significant risks does PGE encounter today?

A. PGE encounters a variety of risks including:

- Hydro and wind availability and weather changes: Weather creates risk for PGE in several ways, including: lower than average stream flows; lower than average wind flows and/or the timing of it; and volatility in electricity usage because of sudden, unexpected weather changes and severe storms. These risks are not mitigated by our decoupling mechanism and 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: Regional economic weakness can adversely affect PGE's revenues. Weakness in the state of Oregon's economy, can lead to a decline in electricity usage as customers conserve electricity in response. 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. Oregon's economy was especially hard-hit during the recession and financial crisis of 2008, and has only recently recovered.

- Uncertainty regarding financial and business operations contingencies: as noted in our SEC annual 10-K and quarterly 10-Q filings.[12] PGE could be vulnerable to cyber security and physical asset attacks. The electric industry is going through accelerated technological changes, which can make a basic premise of the current business model (economies of scales gained from central generation facilities) obsolete. Our workforce is aging, and PGE is starting to experience difficulties in finding replacements for key positions.
- Uncertain federal and state energy policy: 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 from 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 the most recent reports from Wells Fargo and Ladenburg Thalmann in our confidential 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 us for the operational impacts of adverse events. For

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[12] http://investors.portlandgeneral.com/sec.cfm
Starting with page 116,Note 18- 2015 SEC Form 10-K
http://files.shareholder.com/downloads/POR/328496689x0xS784977-16-111/784977/filing.pdf
Starting with page 26 Note 7- the most recent 10/28/16 SEC Form 10-Q

example, recovery from catastrophic events remains a key strategic focus of PGE. PGE's office of Business Continuity and Emergency Management has developed formal recovery plans to address disasters and implement emergency management procedures. PGE is also taking measures to address cyber security risks by increasing Information Technology security staff and evaluating process improvements for detection and prevention of cyber-attacks. Another risk category is PGE's fuel supply. PGE is developing backup plans for fueling in the event of extended outages of natural gas pipelines or coal supply. We are looking at gas dispatch modeling and performing cost-benefit analysis of re-establishing the ability of gas plants to run on oil if pipeline interruptions occur. We are also moving forward with storage solutions and have provided a Notice to Proceed to NW Natural to develop its North Mist storage facility in order to provide long-term no-notice underground natural gas storage to serve our Beaver and Port Westward natural gas fired generating plants.[13]

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, we ensure that we are prepared, aware, and capable of responding to them to the best of our ability and we continue 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, 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.

[13]"NW Natural Receives Notice to Proceed on its North Mist Expansion Project" Nasdaq Global New Wire. 3 October 2016
https://globenewswire.com/news-release/2016/10/03/876446/0/en/NW-Natural-Receives-Notice-to-Proceed-on-its-North-Mist-Expansion-Project.html

VI. Qualifications

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

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts. Locally, I have been on the Board of Directors for Advantis Credit Union since 2007, serving previously on the Audit Committee.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs.

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

A. I received a Bachelor of Science degree in Business Administration with a finance emphasis from the University of Oregon in 2004 and a Master of Business Administration degree from Portland State University in 2009.

I have been employed at PGE since 2005, beginning as an analyst in PGE's Corporate Finance Department. I then worked in PGE's Investor Relations Department. I spent approximately seven years working in PGE's Rates and Regulatory Affairs Department. I then managed PGE's forecasting team including financial and load forecasting, and economic analysis. My current position is Assistant Treasurer and Manager of Corporate Finance & Investor Relations.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1001	Cost of Long-Term Debt
1002	Standard & Poor's and Moody's Investors Service Credit Ratings

Cost of Long-Term Debt

Expected December 31, 2018 - 2018 Test Year

Updated 01.04.2017

(A)	AWO (B)	Type (C)	Description (D)	Issue Date (E)	Maturity Date (F)	Term (G)	Coupon (H)	Gross Proceeds (I)	DD&E Issue Costs (J)	Call Premium & Unamort. DD&E of Refunded Issue (K)	*F/N*	Net Proceeds (L) [I - J - K]	Embedded Cost (M)	Net to Gross Rate (N) [L / I]	Face Amount Outstanding (O)	Net Outstanding (P) [N * O]	Face Amount Weight (Q) [O / Total]	Weighted Rate (R) [Q * M]
1	7000000037	Series MTN	9.310% Series	12-Aug-91	11-Aug-21	30	9.310%	$20,000,000	$176,577	$0		$19,823,423	9.399%	99.117%	$20,000,000	$19,823,423	0.751%	0.071%
2	7000000022	Series VI MTN	6.750% Series	4-Aug-03	1-Aug-23	20	6.523%	$50,000,000	$521,342	$1,946,809	*1*	$47,531,849	6.985%	95.064%	$50,000,000	$47,531,849	1.879%	0.131%
3	7000000023	Series VI MTN	6.875% Series	4-Aug-03	1-Aug-33	30	6.648%	$50,000,000	$521,342	$1,946,809	*1*	$47,531,849	7.046%	95.064%	$50,000,000	$47,531,849	1.879%	0.132%
4	7000000024	FMB	6.310% Series	26-May-06	1-May-36	30	6.310%	$175,000,000	$1,270,865	$6,199,472	*3*	$167,529,663	6.640%	95.731%	$175,000,000	$167,529,663	6.575%	0.437%
5	7000000025	FMB	6.260% Series	26-May-06	1-May-31	25	6.260%	$100,000,000	$723,857	$4,132,982	*2*	$95,143,161	6.662%	95.143%	$100,000,000	$95,143,161	3.757%	0.250%
6	7000000433	FMB	5.800% Series	16-May-07	1-Jun-39	32	5.800%	$170,000,000	$1,447,420	$50,969	*3*	$168,501,611	5.861%	99.119%	$170,000,000	$168,501,611	6.388%	0.374%
7	7000000027	FMB	5.810% Series	19-Sep-07	1-Oct-37	30	5.810%	$130,000,000	$1,627,092	$0		$128,372,908	5.899%	98.748%	$130,000,000	$128,372,908	4.885%	0.288%
8	7000000181	FMB	6.100% Series	13-Apr-09	15-Apr-19	10	6.100%	$300,000,000	$2,608,223	$0	*4*	$297,391,777	6.218%	99.131%	$300,000,000	$297,391,777	11.272%	0.701%
9	7000000182	FMB	5.430% Series	3-Nov-09	3-May-40	30.5	5.430%	$150,000,000	$1,034,283	$0		$148,965,717	5.477%	99.310%	$150,000,000	$148,965,717	5.636%	0.309%
10	7000000185	PCB	Clstrp 98A Fixed	11-Mar-10	1-May-33	23	5.000%	$97,800,000	$688,885	$1,521,911	*5*	$95,589,204	5.168%	97.739%	$97,800,000	$95,589,204	3.675%	0.190%
11	7000000036	PCB	Brdmn 98A Fixed	11-Mar-10	1-May-33	23	5.000%	$23,600,000	$166,234	$912,065	*5*	$22,521,701	5.346%	95.431%	$23,600,000	$22,521,701	0.887%	0.047%
12	3000000509	FMB	4.47% Series	27-Jun-13	15-Jun-44	31	4.470%	$150,000,000	$1,121,463	$0		$148,878,537	4.515%	99.252%	$150,000,000	$148,878,537	5.636%	0.254%
13	3000000510	FMB	4.47% Series	29-Aug-13	14-Aug-43	30	4.470%	$75,000,000	$560,731	$0		$74,439,269	4.516%	99.252%	$75,000,000	$74,439,269	2.818%	0.127%
14	3000000576	FMB	4.74% Series	15-Nov-13	15-Nov-42	29	4.740%	$105,000,000	$671,615	$0		$104,328,385	4.781%	99.360%	$105,000,000	$104,328,385	3.945%	0.189%
15	3000000575	FMB	4.84% Series	16-Dec-13	15-Dec-48	35	4.840%	$50,000,000	$319,817	$0		$49,680,183	4.878%	99.360%	$50,000,000	$49,680,183	1.879%	0.092%
16	3000000696	FMB	4.39% Series	15-Aug-14	15-Aug-45	31	4.390%	$100,000,000	$628,548	$0	*6*	$99,371,452	4.427%	99.371%	$100,000,000	$99,371,452	3.757%	0.166%
17	3000000697	FMB	4.44% Series	15-Oct-14	15-Oct-46	32	4.440%	$100,000,000	$628,548	$0	*6*	$99,371,452	4.477%	99.371%	$100,000,000	$99,371,452	3.757%	0.168%
18	3000000698	FMB	3.51% Series	17-Nov-14	15-Nov-24	10	3.510%	$80,000,000	$502,838	$0	*6*	$79,497,162	3.585%	99.371%	$80,000,000	$79,497,162	3.006%	0.108%
19	3000000789	FMB	3.55% Series	15-Jan-15	15-Jan-30	15	3.550%	$75,000,000	$375,000	$0		$74,625,000	3.593%	99.500%	$75,000,000	$74,625,000	2.818%	0.101%
20	3000000831	FMB	3.50% Series	20-May-15	20-May-35	20	3.500%	$70,000,000	$350,000	$2,665,260	*8*	$66,984,740	3.810%	95.692%	$70,000,000	$66,984,740	2.630%	0.100%
21	3000000898	FMB	2.51% Series	6-Jan-16	6-Jan-21	5	2.510%	$140,000,000	$627,125	$8,536,430	*7*	$130,836,445	3.966%	93.455%	$140,000,000	$130,836,445	5.260%	0.209%
22	2017-1	FMB	4.24% Series	1-Mar-17	1-Mar-47	30	4.240%	$125,000,000	$875,000	$0	*9*	$124,125,000	4.282%	99.300%	$125,000,000	$124,125,000	4.697%	0.201%
23	2017-2	FMB	4.24% Series	1-Oct-17	1-Oct-47	30	4.240%	$125,000,000	$875,000	$0	*9*	$124,125,000	4.282%	99.300%	$125,000,000	$124,125,000	4.697%	0.201%
24	2017-3	FMB	4.24% Series	1-Nov-17	1-Nov-47	30	4.240%	$200,000,000	$1,400,000	$0	*9*	$198,600,000	4.282%	99.300%	$200,000,000	$198,600,000	7.515%	0.322%
			Annual expense from loss on reacquired debt							$17,139		($17,139)						
			Totals					$2,661,400,000	$19,721,805	$27,929,846		$2,613,748,349			$2,661,400,000	$2,613,765,488	100.00%	5.169%
			Cost of LT Debt (includes annual expense from loss on reacquired debt)															**5.170%**

Losses on Other Reacquired Debt	Issue Date	Mat. Date	Reacquisition Date	Gross Proceeds	Total Gain/Loss to Amortize	2018 Expense
7000000(5.450% Colstrip 98B Fixed PCB due	1-May-03	1-May-33	1-May-09	$21,000,000	$411,622	$17,139
						$17,139

Footnotes

1 $5.8 million in call premia resulting from acquisition of 9.46% and 7.75% issues was allocated evenly among August 2003 issues (see UE 180, PGE Exhibit 1400, page 3).

2 There was a $12 million call premium on the 8.125% redeemed issue. A portion was disallowed in UE 180. The remainder is rolled into the new debt and will be paid over the period of the May 2006 issuances.

3 $5.1 million Trojan 1990B PCBs redeemed early in June 2007. Unamortized loss of $50,969 was added to the 5.80% series $170MM issued in May 2007 used to redeem the PCBs.

4 "DD&E Issue Costs" (column J) was updated to reflect $222,000 discount to par at issuance.

5 PCB issues put-back to PGE in May 2009. PGE re-marketed in March 2010 (due on original maturity date of 05/01/2033).

6 See next tab for Report of Securities

7 2016 Q1 issuance on Lines 21 is updated with 140M issuance of FMB in January 2016.

8 The 6.80% $67M 7-year series maturing Jan. 2016 earlier replaced by a like 7-year pro forma series in 2016 is now updated to New Actual Line 20 data.

Standard & Poor's and Moody's Investors Service Credit Ratings

	S&P	Rating Date	Moody's	Rating Date
Senior Secured Debt	A-	6/23/2016	A1	7/8/2016
Senior Unsecured	BBB	6/23/2016	A3	7/8/2016
Short-term/ Commercial Paper	A-2	6/23/2016	P-2	7/8/2016

"Credit Opinion: Portland General Electric Company" June 23, 2016. Standard & Poor's
"Credit Opinion: Portland General Electric Company" July 8, 2016. Moody's Investors Service

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

ROE

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bente Villadsen, Ph.D.

February 28, 2017

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Where r_s is the cost of capital for investment S; r_f is the risk-free rate; β_S is the beta risk measure for the investment S; and MRP is the market risk premium. The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities. I estimate this model using Value Line betas, the risk-free rate

I. Introduction and Summary

Q. Please state your name, occupation and relationship with Portland General Electric Company ("PGE").

A. My name is Bente Villadsen and I am a principal at The Brattle Group (Brattle). My business address is The Brattle Group, 44 Brattle Street, Cambridge, MA 02138, USA. I have been asked by Portland General Electric Company (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 after January 1, 2018.

My qualifications are included at the end of my testimony.

Q. Please summarize your results.

A. The results I arrived at are detailed in Table 1 below.[1]

Table 1: Summary of ROE Estimates for PGE[2]

	Range of Estimates	Midpoint
DCF Models	9.0% - 10.3%	9.65%
Risk Premium Model	9.9% -10.4%	10.15%
Other Tests[3]	9.3% - 10.2%	9.75%
Range	9.3% - 10.3%	n/a
Midpoint / Average	9.8%	9.85%

I understand that the Commission in the past has relied primarily on the Discounted Cash Flow (DCF) model and in particular the multi-stage DCF model, which I estimate at 9.1%

[1] The Public Utilities Commission of Oregon (Commission) has, in the past, given no weight to the CAPM (Order 01-777, p. 32). Therefore, I use the CAPM as a check on the other estimates rather than a primary method in this matter.

[2] Data cited in Table 1 use all sample companies.

[3] I use the CAPM as a check, which results in an ROE of 9.2% to 10.2%. For 2016, the average allowed ROE for integrated electric utilities was 9.77% (excluding VA limited-issue Rider matters, which often involve generation incentives). See PGE Exhibits 1103 and 1105 for details. Source: Authorized ROE data from SNL Financial as of 1/9/2017.

using a combination of the Office of Management and Budget (OMB) and Blue-Chip GDP long-term growth rate (and at 9.0% using Blue Chip alone).[4] Thus, the multi-stage DCF model results in estimates that are below the midpoint, but PGE's smaller market capitalization warrants a size premium of 60-70 basis points, which results in a multi-stage DCF result of 9.6% - 9.8%.[5] Other DCF models, the risk premium model, as well as other tests find a range of 9.0% to 10.4%. If I eliminate the highest and lowest estimate, my range is 9.3 to 10.3%, which includes PGE's requested ROE of 9.75%, which is slightly below both my estimated midpoint of 9.8% and the average of the midpoint estimates of 9.87%. I further note that once PGE's smaller size is considered, the multi-stage DCF fully supports PGE's request. Finally, I note that the average allowed ROE for integrated electric utilities in 2016 was 9.77%. Therefore, PGE's request is conservative.

Q. How did you estimate the ROE for PGE?

A. To assess the cost of capital for PGE, I start by selecting a sample of integrated electric utilities from Value Line's universe of electric utilities. The sample companies are selected to be comparable to PGE, so I include electric utilities that (i) have more than 50% regulated assets and (ii) own generation. In addition, the companies are screened based on financial criteria such as credit ratings and on data availability. For each company, I then estimated the cost of equity using standard methods including two versions of the DCF model, the risk premium model, a review of recently allowed ROE, and as a test, two versions of the Capital

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[4] I use the consensus forecast of the nominal GDP growth rate for 2023-2027 from the October 2016 Edition of Blue Chip Economic Indicators. In the 2017 Edition of Analytical Perspectives: Budget of the U.S. Government, the OMB forecasts an average nominal GDP growth rate of 4.3% from 2023-2026 (see page 12, Table 2-1). For the combination of Blue Chip and OMB GDP growth rates, I use 4.2% — the average of 4.1% and 4.3%.

[5] I note that according to Duff and Phelps / Ibbotson, "SBBI 2016 Classic Yearbook," (SBBI 2016) pp. 7-3, PGE's market capitalization makes it a decile 7 company, whereas the average of the comparable companies is decile 3-4 in terms of size. According to page 7-16, the size premium that is warranted for a company of PGE's size relative to the comparable companies is 60-70 basis points.

Asset Pricing Model (CAPM). I ensure consistency between the capital structure used to derive the cost of equity estimates and PGE's regulatory capital structure and also evaluate critical risk factors that may differ between PGE and the sample. Specifically, I note that PGE is smaller than the majority of the sample companies and has just finished integrating a large amount of new generation (e.g., Carty and wind) into its supply mix. I also note that the average credit rating in my sample is BBB+ using Standard & Poor's (S&P) ratings, while S&P rates PGE BBB (Moody's rates PGE higher at A3).[6]

[6] Ratings cited in my work papers are S&P ratings as reported by Bloomberg.

II. Cost of Capital Theory

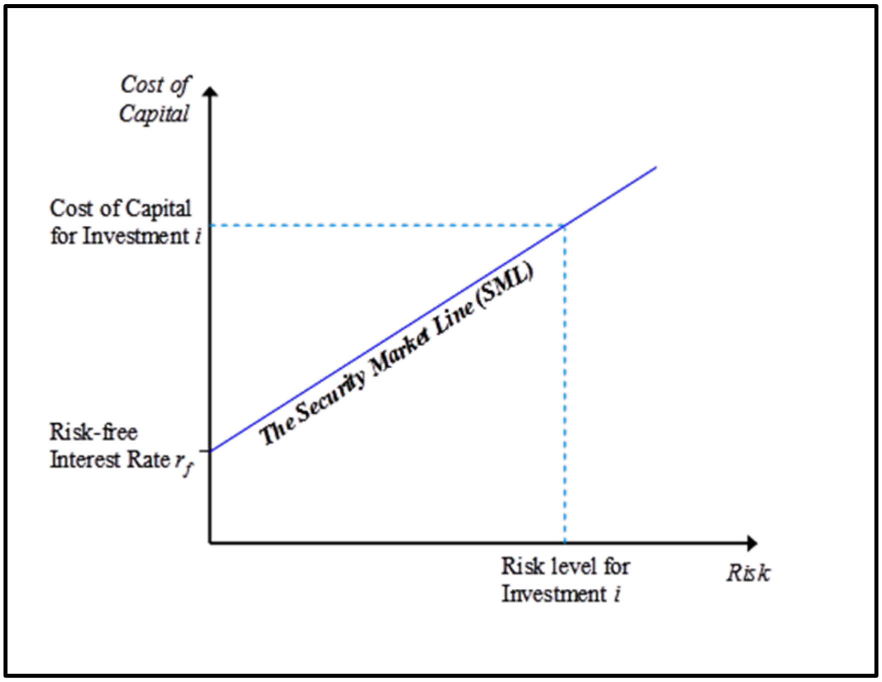
A. Cost of Capital and Risk

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. In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected," as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

The definition of the cost of capital recognizes a tradeoff between risk and return that can be represented by the "security market risk-return line" or "Security Market Line" for short. This line is depicted in Figure 1 below. The higher the risk, the higher the cost of capital required.

Figure 1: The Security Market Line



Q. Why is the cost of capital relevant in rate regulation?

A. As noted above, the "cost of capital" is the return that investors expect to earn on investments of comparable risk[7] and is viewed as consistent with the U.S. Supreme Court's opinions in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) as well as with Oregon law, ORS ¶756.040, which, consistent with the Bluefield and Hope, holds that:

> Rates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility, with a return to the equity holder that is:
> (a) Commensurate with the return on investments in other enterprises having corresponding risks; and
> (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.[8]

[7] See Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases," *Bell Journal of Economics & Management Science* 3:58-97 (1972).

[8] 2015 ORS ¶ 756.040. Available at http://www.oregonlaws.org/ors/756.040.

From an economic perspective, rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers over pay for service. Regulatory commissions normally try to prevent such outcomes unless there are offsetting benefits (e.g., from incentive regulation that reduces future costs). At the same time, an expected return below the cost of capital does a disservice not just to investors but, importantly, to customers as well. Such a return denies the company the ability to attract capital, to maintain its financial integrity, and to expect a return commensurate with that of other enterprises attended by corresponding risks and uncertainties.

More important for customers, however, are the broader economic consequences of providing an inadequate return to the company's investors. In the short run, deviations from the expected rate of return on the rate base from the cost of capital may seemingly create a "zero-sum game"— investors gain if customers are overcharged, and customers gain if investors are shortchanged. But in fact, in the short term, a return below the cost of capital may adversely affect the utility's ability to provide stable and favorable rates because some potential efficiency investments may be delayed and the company may be forced to file more frequent rate cases. Moreover, in the long run, inadequate returns are likely to cost customers—and society generally—far more than may be saved in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. Without access to investor capital, the company may be forced to forgo opportunities to maintain, upgrade, and expand its systems and facilities in ways that decrease long run costs. Indeed, the cost to consumers of an undercapitalized industry can be far greater than any short-run gains from shortfalls in the cost of capital. This is especially true in capital-intensive industries (such as the electric utility industry), which feature systems that take a long time to decay. Such long-lived infrastructure assets cannot be repaired or replaced overnight, because of the time necessary to plan, permit, and construct the facilities. Thus, it is in customers' interest not only to make sure the return investors expect does not exceed the cost of capital, but also to make sure that the return does not fall short of the cost of capital.

The cost of capital cannot be estimated with perfect certainty, and other aspects of the way the revenue requirement is set may mean investors expect to earn more or less than the cost of capital, even if the authorized rate of return exactly equals the cost of capital.

B. The Impact of Risk on the Cost of Capital

Q. Please summarize how you consider risk when estimating the cost of capital.

A. First, I select my comparable sample to have as comparable business risks as possible to PGE. Second, as the cost of equity depends on the leverage of the company to which it is applied, I consider the difference in leverage between the data from which I estimate the cost of equity and PGE. Third, I consider any PGE-specific risk that may help me place the Company within the range of my estimated cost of equity or if unique circumstances dictate it, above or below the range.

Q. Why is capital structure important for the determination of the cost of equity for PGE?

A. As shown by Professor Hamada,[9] shareholders in a company with more debt face more equity risk and the return on equity needs to increase. Commission Staff has in past

9 Robert S. Hamada, "Portfolio Analysis, Market Equilibrium and Corporate Finance," *The Journal of Finance* 24: 13-31 (March 1969).

proceedings acknowledged this principle.[10] One way to take the phenomena into account is to determine the after-tax weighted-average cost of capital for the entities and ensure that figure stays constant between the estimate obtained for the sample and the entity to which it is applied.[11] Other methods are more applicable to the CAPM and use the beta estimate.

Q. Please explain how you calculate and implement the methodology.

A. The after-tax weighted average cost of capital (ATWACC) is calculated as the weighted average of the after-tax cost of debt capital and the cost of equity. Specifically, the following equation pertains:[12]

$$ATWACC = r_D \times (1 - T_C) \times \%\ D + r_E \times \%\ E \qquad (1)$$

where r_D = market cost of debt,

r_E = market cost of equity,

T_C = corporate income tax rate,

$\%D$ = % debt in the capital structure, and

$\%E$ = % equity in the capital structure

The ATWACC is commonly referred to as the WACC in financial textbooks and is used in investment decisions.[13] The return on equity, consistent with the sample's overall cost of capital estimate, the market cost of debt, the corporate income tax rate, and the amount of debt and common equity in the capital structure, can be determined by solving equation (1) for r_E. Having determined the after-tax weighted-average cost of capital for the

[10] See, for example, UE 283 Exhibit 200, p. 8.
[11] For other methods such as the CAPM, other methods are readily available and I discuss those in Exhibit PGE1103 and 1104.
[12] The equation is shown with only debt and common equity. If the capital structure has preferred equity, add the following term (rP × % P) to the right-hand side of the equation.
[13] See, for example, Brealey, Myers and Allen (2013), *Principles of Corporate Finance*, 11th Edition, p. 221.

sample companies, I can determine what ROE I need to ensure the same after-tax weighted-average cost of capital is applied to PGE.[14]

Q. Why is this relevant to this proceeding?

A. The ATWACC is one of several procedures in my analysis; it is important because it allows a comparison between the sample companies' costs of capital estimates that are based on market data and the cost of capital for PGE, which is based on book value figures. Two otherwise identical companies with different capital structures will typically have different costs of equity because the risks to equity holders depend on financial leverage (i.e., the amount of debt in the capital structure of the company). This makes it difficult to compare cost-of-equity estimates among companies that have different capital structures. The effect of varying financial leverage on the risk-return tradeoffs of companies means that simply averaging individual cost-of-equity estimates across a sample generally does not provide meaningful information about an appropriate representative cost of capital for the industry. Thus, if the capital structure used to estimate the benchmark sample's cost of equity differs from the capital structure used to regulate PGE, it is necessary to consider the leverage impact.

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 usually is applied to book value capital structures, it is the book value capital structure that is relevant for the risk premium method.

[14] I refer to the ATWACC to distinguish it from the WACC used in regulatory proceedings, which is the weighted-average of the after-tax cost of equity and the pre-tax cost of debt instead of the after-tax cost of debt.

Q. What is the basis for the development of the method?

A. The weighted-average cost of capital – as it is called in textbooks—is a fundamental method used by financial economists to measure the cost of capital. It is a standard topic taught in graduate level courses in corporate finance and is based upon the work of Professors Franco Modigliani and Merton Miller. Each separately won the Nobel Prize in Economics, in part, for developing the theories underlying the method. It is critical to keep in mind that the weighted average cost of capital method is one useful tool to assist in the analysis of the cost of capital. All cost of capital witnesses estimate the cost of equity using the DCF, risk premium, CAPM, and other models, and all must interpret the results relative to the risk of the regulated company at issue. The purpose of the method is to allow an "apples to apples" comparison of the results of the sample companies by adjusting for differences in financial risk due to differences in capital structure. It is consistent with the use of rate base measured on the basis of book value, and does not require a regulator to "rubber stamp" the current market value of the regulated company's stock.

Q. Are there other PGE-specific risk factors?

A. Yes, the majority of the publicly traded electric utilities in the U.S., as well as the companies, I select for my sample, are larger than PGE. For example, the market capitalization for 15 of my 25 sample companies is above $10 billion. The average is more than 3.5 times larger than PGE's market capitalization of only $3.8 billion.[15]

Q. Why does the size of PGE matter?

A. Empirically, investors have required a higher premium to invest in smaller companies than in larger ones. For example, SBBI data indicate that small-cap companies on average have a

[15] See Table 2 in Section IV (B) below for details.

return on equity that is 0.70% higher than that of mid-cap companies.[16] Therefore, empirical evidence suggests that investors in smaller and mid-cap companies require a higher return than do investors in larger companies. The majority of electric utilities (including my sample companies) are materially larger than PGE. Only four companies have a market cap below that of PGE, while 17 companies have a market cap that is more than twice that of PGE.[17] Thus, empirical evidence suggests that investors in PGE require a premium over and above that required for larger companies. Because the sample consists of both smaller and larger companies, the premium is best determined using the average or median of the size deciles provided by SBBI. Looking specifically to the size deciles reported in SBBI 2016, the data indicates that PGE's size merits a size premium of 0.60% to 0.70%.[18]

Q. What other risks create a higher overall risk for PGE?

A. PGE has in recent years undertaken substantial capital investment in generation, for example, the 440 MW natural gas Carty generating facility at a cost of about $640 million, and expects to make additional capital expenditures in 2017 of about $604 million.[19] Because PGE is substantially smaller than the average proxy company, and it has the need to integrate a large amount of new generation in its generation mix, it has a relatively high operating risk as measured by the addition of fixed costs.

Q. What conclusions do you draw from the discussion above?

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[16] Roger G. Ibbotson, "*2016 SBBI Yearbook*," Duff & Phelps 2016 (SBBI 2016), p. 7-16.
[17] See Table 2 in Section IV (B) below for details.
[18] SBBI 2016, pages 7-3 and 7-16.
[19] Portland General Electric, Investor Presentation December 2016. Available at http://files.shareholder.com/downloads/POR/3297335118x0x919464/ABED609B-D34E-4296-ABA3-3214FFD5858B/12-2016_PGE_Investor_Presentation_Wells_Fargo.pdf

A. Because there is a link between capital structure[20] and the size premium,[21] I formally adjust for the leverage, but do not adjust for the size albeit PGE could reasonably be placed in the upper end of the range I estimate for the sample.

[20] For example, K.C. Chan and N.-F. Chen, "Structural and Return Characteristics of Small and Larger Firms," *The Journal of Finance* 46, 1992, pp. 1467-1484 or Brealey, Myers, and Allen, "*Principles of Corporate Finance*," 11th edition, 2014, pp. 436 – 437.
[21] Morningstar / Ibbotson, *SBBI 2014 Classic Yearbook*, p. 109.

III. Impact of the Economy and Markets on the Cost of Equity

A. Interest Rates

Q. What are the relevant developments regarding interest rates?

A. Interest rates and especially government bond yields have been low, but have started to increase. The Federal Reserve (Fed) raised the target for the federal funds rate on December 14, 2016 and signaled that further increases are likely.[22] I also note that forecasting services such as Blue Chip Economic Indicators increased the forecasted yield on 10-year government bonds by 40 basis points between their October / November and the December issues.[23] Further, the spread between utility bond yields and government bond yields of the same maturity remains higher than they have been historically, thus indicating that the government bond yield remains suppressed or that investors' required premium to invest in securities that are not risk-free are elevated.

Figure 2 below shows the development in BBB rated utility and Government bond yields from 2002 to today.[24] It is evident that the yield spread (the difference between the yield on BBB rated utility bonds and government bonds) is higher than its historical average and higher than at the time of PGE's most recent rate case filing (UE 294).

Figure 3 shows the spread between A rated utility bonds and government bond yields along with the average spread prior to the financial crisis. Again, it is evident that the spread is

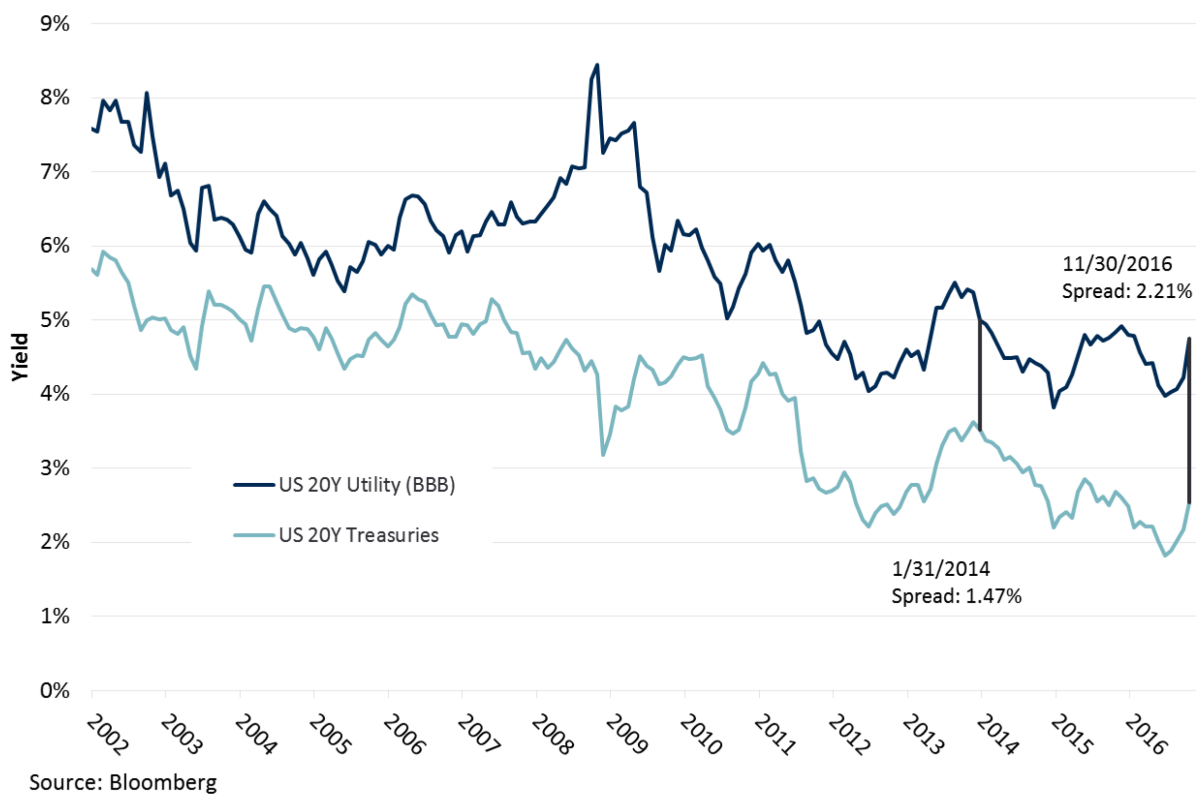
[22] The Federal Reserve increased the target for the federal funds rate from ¼ to a range of ½ to ¾ on December 14, 2016. Source: Federal Reserve Press Release December 14, 2016; https://www.federalreserve.gov/newsevents/press/monetary/20161214a.htm

[23] *Blue Chip Economic Indicators*, October 2016, November 2016, and December 2016.

[24] For clarity "BBB rated" refer to bonds in the range of BBB- through BBB+ and "A rated" reference bonds in the range of A- through A+. The majority of electric utilities are low A or high BBB rated.

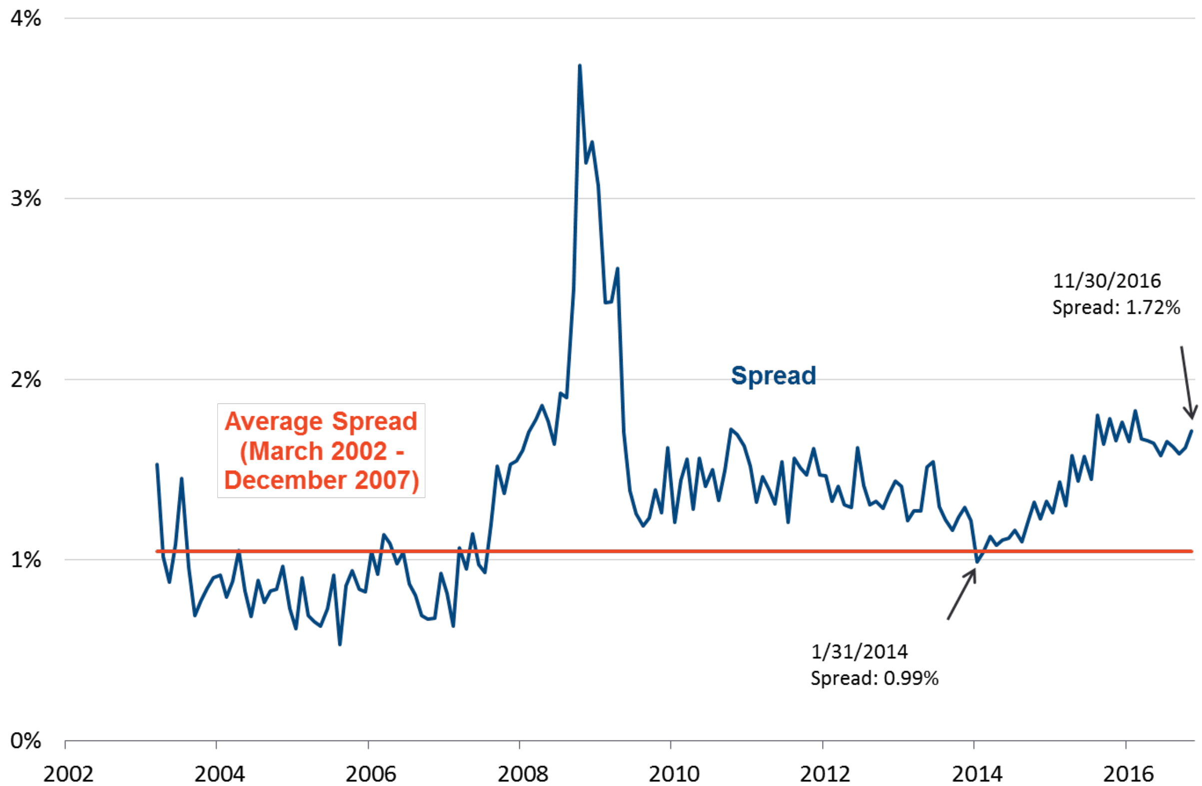
greater. Thus, a review of both BBB rated and A rated bonds clearly illustrates the increase in the spread between the utility bond yield and government bond yields.[25]

Figure 2: BBB Utility Bond and Government Bond Yields: 2002 – November 2016



[25] Bloomberg data summarized in Exhibit PGE 1106 shows that the average spread between A rated utility bond yields and government yields was 0.93% for the period 1991-2007 (before the financial crisis), whereas it increased dramatically during the financial crisis and has remained elevated. The same exhibit shows that the spread between BBB rated utility bond yields and government bond yields averaged 1.23% between 1991 and 2007 and was only slightly above 1% for the period 2002 to 2007.

Figure 3: Spread between A Rated Utility and 20-Year Government Bond Yield



Source: Bloomberg.

Q. How does the current spread between utility and government bond yields compare to the historical spread?

A. As shown in Figure 2 and Figure 3 above, the spread between BBB rated utility bond yields or between A rated utility bond yields and government bond yields is elevated. At the end of November 2016, the BBB spread stood at 2.21%, which is approximately 95 basis points higher than prior to the 2008-09 financial crisis. At the same time the A rated utility bond yield spread was 1.72% for an increase of about 55 basis points over the pre-crisis level. Not only is the yield spread increased relative to its pre-crisis levels, but it is also greater relative to the level in the more recent past as illustrated in the figures above.

Q. What is the expected trend for interest rates?

A. Blue Chip Economic Indicators expects that the yield on 10-year Treasury Notes will increase to 2.8% in 2018, or an increase of about 40 basis points over its yield at the end of November 2016. The publication forecasts additional increases for 2019 and beyond.[26] Comparably, the Congressional Budget Office predicts that the rate on 10-year treasury notes will increase to 4.1% by the second half of 2019.[27] These expectations are consistent with the current downward pressure on Government bond yields, which has in part been caused by the Federal Reserve's quantitative easing program and general stimuli of the U.S. economy.[28] As the downward pressure eases off, interest rates are expected to increase.

Q. How do these developments impact the cost of equity analysis?

A. There are several ways in which the current interest rate environment affects the cost of equity analysis. First, it impacts the risk premium estimates through a lower government bond yield.

Second, if the spread between the yield on utility (or corporate) bonds and government bonds (the "yield spread") widens, it indicates that the premium that investors require for holding securities other than government bonds has increased. Thus, a higher than normal yield spread is one indication of the higher risk premiums currently prevailing in capital markets. Investors consider a risk-return tradeoff (like the one displayed in Figure 1 above) and select investments based upon the desired level of risk. Higher yield spreads reflect the fact that the return on corporate debt is higher relative to government bond yields than is

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[26] *Blue Chip Economic Indicators*, October 2016 and U.S. Department of The Treasury. Only the October and March issues of Blue Chip Economic Indicators provide long-term forecasts.

[27] Congressional Budget Office, "The Budget and Economic Outlook: 2016-2026," January 2016, p. 7.

[28] For a summary of the magnitude of the Federal Reserve's purchase program, see, for example, Bloomberg, "The Fed Eases Off," September 16, 2015.

normally the case, even for regulated utilities. Because equity is more risky than debt, this means that the spread between the cost of equity and government bond yields must also be higher; i.e., the premium required to hold equity rather than government bonds has increased. If this fact is not recognized, then the traditional cost of capital estimation models will underestimate the cost of capital prevailing in the capital markets.

Third, in times of economic uncertainty (such as the present) investors seek to reduce their exposure to market risk. This precipitates a so-called "flight to safety,"[29] wherein demand for low-risk government bonds rises at the expense of demand for stocks. If yields on bonds are extraordinarily low, however, any investor seeking a higher expected return must choose alternative investments such as stocks, real estate, gold or collectibles. Of course, all of these investments are riskier than government bonds, and investors demand a risk premium (perhaps an especially high one in times of economic uncertainty) for investing in them. Because utilities are considered necessary and subject to regulation, utility stocks may have experienced an inflow of capital that usually would have been invested elsewhere. Moving from more risky to less risky investments is often referred to as a "flight to safety" and utility stock may have experienced this phenomenon to a larger degree than other stock because they traditionally have paid a substantial portion of their earnings as dividends, so that investors' return is less dependent upon the development in markets in general.

One possible explanation of the current elevated level of the yield spread is that current and near-term expected levels of government bond yields are artificially depressed due to monetary policy.[30] I emphasize that the U.S. government bond yields (as well as that of

[29] Sometimes referenced as "flight to quality."

[30] As of Q2, 2016, the Federal Reserve held approximately $1.8 trillion of mortgage-backed securities, whereas the magnitude was less than $0.5 trillion in mid-2009. Source: Bloomberg, "The Fed Eases Off," September 16, 2015

many other western countries) is expected to increase substantially over the next several years.[31] An alternative explanation is that the return investors require to invest in securities that are not risk-free has increased, so that the risk premium investors require to hold equity is elevated.

The recent increase in government bond yields, the increase in the Federal Funds rate as well as the projected increase in government bond yields are indicators that the current yield on government bonds is below investor expectations for the next few years.[32]

Q. What are the implications of elevated yield spreads to the cost of equity?

A. The increase in the yield spread indicates that (i) the current long-term government bond yields are depressed relative to their normal levels and / or (ii) investors are demanding a premium higher than the historical premium to hold securities that are not risk free. Regardless of the interpretation, the consequence is that if cost of equity is estimated using the current risk-free rate and/or without regard to the elevation of the premium required to hold equity relative to government issued debt, then the cost of equity will be downward biased.

B. Market Volatility

Q. Why is the stock market's volatility important?

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and Federal Reserve Bank, "Combined Quarterly Financial Report," June 30, 2016. Available at https://www.federalreserve.gov/monetarypolicy/files/quarterly-report-20160630.pdf

[31] If investors' believe the yield on government bonds will soon elevate, they may demand higher yields on corporate debt relative to the prevailing government bond yields, thus widening the yield spread.

[32] The expectation of increasing bond yields has been slower to materialize than most forecasting services have predicted over the last few years. Researchers from the Federal Reserve Bank of St. Louis found that forecasts of U.S. T-bill rates tended to under-predict the increase when yields were increasing and over-predict when yields were declining, so that the results were closer-to-normal prediction than what materialized. They found no evidence that expectations were systematically too high or too low. See R.W. Hafer and S.E. Hein. "Comparing Futures and Survey Forecasts of Near-Term Treasury Bill Rates." *Federal Reserve Bank of St. Louis Review.* May/June, (1989), 33-42.

A. Academic research has found that investors expect a higher risk premium during more volatile periods. The higher the risk premium, the higher the required return on equity. For example, French, Schwert & Stambaugh (1987) found a positive relationship between the expected market risk premium (MRP) and volatility:

> We find evidence that the expected market risk premium (the expected return on a stock portfolio minus the Treasury bill yield) is positively related to the predictable volatility of stock returns. There is also evidence that unexpected stock returns are negatively related to the unexpected change in the volatility of stock returns. This negative relation provides indirect evidence of a positive relation between expected risk premiums and volatility.[33]

A measure of the market's expectations for volatility is the VIX index, which measures the 30-day implied volatility of the S&P 500 index. These indices are also referenced as the "investor fear gauge." While the long-term average for the VIX is a bit below 20, the VIX has been below its long-term average for a period, but increased substantially in mid to late June to reach about 26 on June 24, 2016.[34] As shown in Figure 4 below the VIX has since been at or below its historical level. Thus, the yield spread and the market volatility index are providing different signals about the current state of the economy.

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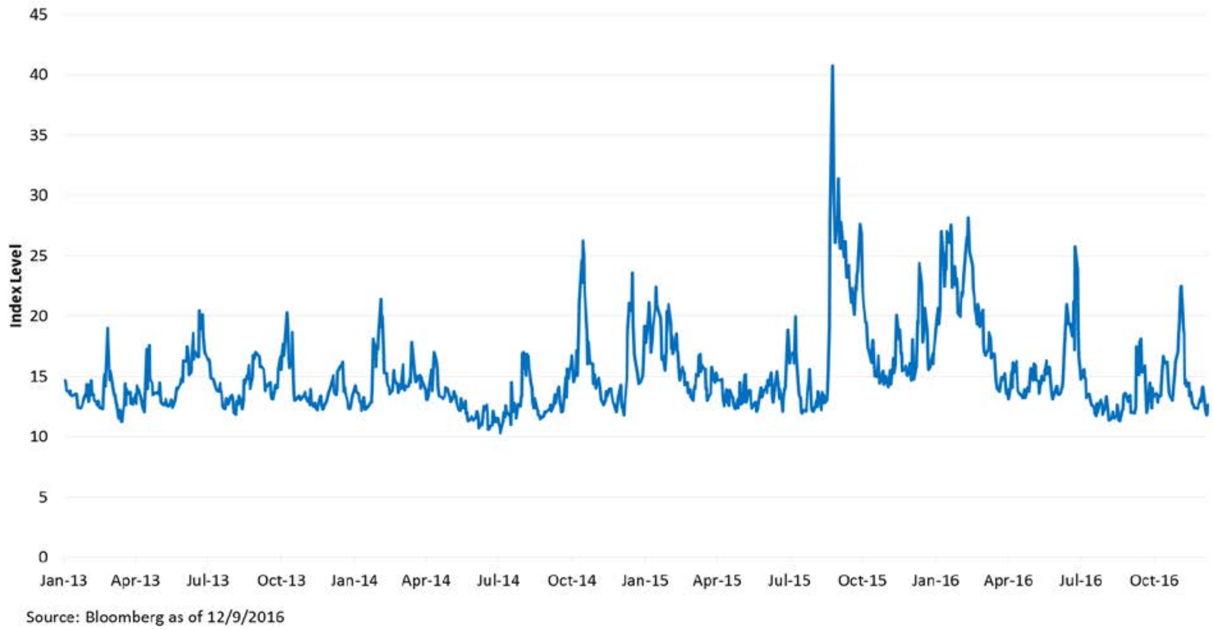
[33] K. French, W. Schwert and R. Stambaugh (1987), "Expected Stock Returns and Volatility," *Journal of Financial Economics*, Vol. 19, p. 3.

[34] Bloomberg. It has since declined.

Figure 4: Volatility Index



Q. Please explain "risk aversion."

A. Risk aversion is the recognition that investors dislike risk, which means that for any given level of risk, investors must expect to earn an appropriate return to be induced to invest. An increase in risk aversion means that investors now require a higher return for that same level of risk.

Q. Do you have any evidence that the return premium demanded by investors for taking risk is higher than it was prior to the 2008-09 financial crisis?

A. Yes. Looking to forecasted MRP, both academic research and financial data services such as Bloomberg have found an increase in the expected MRP compared to prior to the financial crisis. For example, Bloomberg's expected MRP currently stands at about 7.5% over 10-year bonds, while the historical arithmetic average MRP from 1926 to 2015 is 6.9%

over approximately 20-year bonds.[35] Thus, the Bloomberg forecast indicates that the MRP is slightly elevated, while the yield spread shown in Figure 3 indicates a substantial increase in the current MRP.

Q. Are there other indications that the MRP has increased since the 2008-09 financial crisis?

A. Yes. A recently updated analysis by Duarte and Rosa of the Federal Reserve of New York aggregates the results of many models of the required MRP in the U.S. and tracks them over time. This analysis finds a very high MRP in recent years.

The analysis estimates the MRP that results from a range of models each year from 1960 through the present.[36] The analysis then reports the average as well as the first principal component of results.[37] The analysis then finds that the models used to determine the risk premium are converging to provide more comparable estimates and that the average annual estimate of the MRP was at an all-time high in 2013. These estimates are reasonably consistent with those obtained from Bloomberg and the consistent elevation of the MRP over the historical figure indicates that the elevated level is persistent. Figure 5 below shows Duarte and Rosa's summary results.

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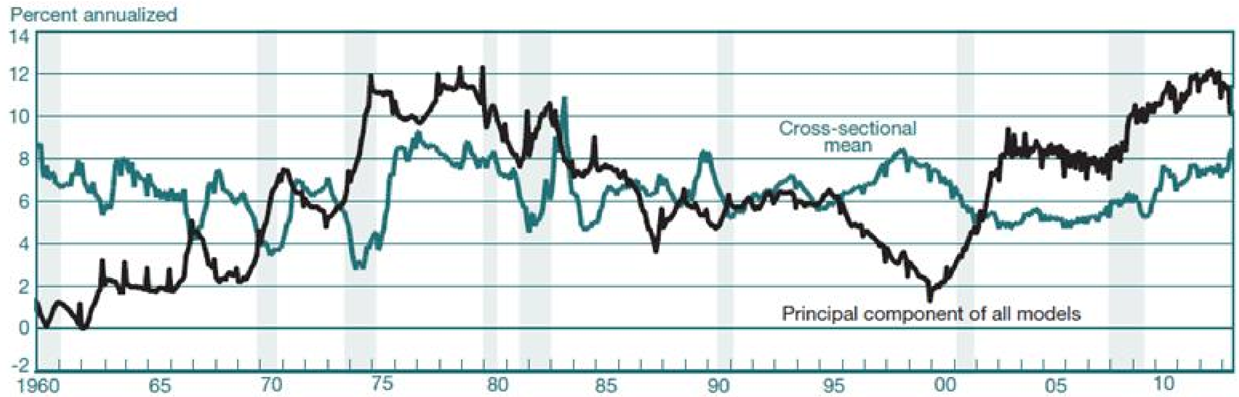
[35] Bloomberg and Duff & Phelps, "*2016 Valuation Handbook: Guide to Cost of Capital*," p. 3-24, respectively. For the purpose of determining the MRP, textbooks such as Stephen A. Ross, Randolph W. Westerfield, and Jeffrey Jaffe, "*Corporate Finance*," 10th Edition, 2013, p. 326. Recommend that the MRP estimate be based on as long a period as there are reliable data for.

[36] Fernando Duarte and Carlo Rosa, "The Equity Risk Premium: A Review of Models," Federal Reserve Bank of New York, December 2015 (Duarte & Rosa 2015).

[37] Duarte & 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 most variability among the 20 models over time.

Figure 5
Duarte and Rosa's Chart 3
One-Year Ahead MERP and Cross-Sectional Mean of Models



Q. Are there other reasons why capital markets may continue to exhibit higher than historical volatility?

A. Yes, 2016 has seen a number of events that have or may affect financial markets. Notably, the U.K. decision to leave the European Union (Brexit) impacted markets, the impact of the change of leadership in the U.S. is unclear at this point, and the continued weakness in Europe may well impact financial markets going forward.

C. Price to Earnings Ratio

Q. Are there other features of financial markets that are currently unusual?

A. Yes. The current level of many companies, including utilities, Price-to-Earnings (P/E) ratio is higher than what has been experienced historically. Empirically, the P/E ratio increases when interest rates decline. This is shown in Figure 6 below.

Figure 6: Relationship Between Average Price / Earnings Ratio and 20-Year Treasury Bond Yield[38]

Source: Bloomberg (using quarterly data from 1990 through Q3, 2016)

Q. Please explain the relationship between the P/E ratio and the 20-year government bond yield of interest in your analysis.

A. The dividend yield, which is calculated as Dividends divided by Price (D/P), is closely related to the P/E ratio as dividends are paid out of earnings. If the P/E ratio is very high (low), then the Earnings-to-Price ratio is low (high) and so is the dividend yield (D/P). The average electric utility pays approximately 60% of its earnings as dividends, so if the P/E ratio increases from, for example, 16 to 17 (6¼%), then the Earnings / Price ratios declines by about 0.37% (from 1/16% to 1/17%) and the dividend yield declines by 0.22% (60% × 0.37%). My statistical analysis found that the mean / median P/E ratio increases by 1.0 and 1.4, when the 20-year government bond yield decline by 1%. Using this range and a dividend payout ratio of 60%, I find that if the P/E ratio increases by, for example, 1.4 for each 1% decline in the government bond yield, then the E/P ratio declines by 0.71 (=1/1.4)

[38] See PGE Exhibit 1107 provides the regression analysis as well as the approximate dividend payout.

for each 1% decline in the yield and if the dividend payout ratio is 60%, the dividend yield would decline by about 43 basis points (=60% × 0.71). Therefore, if the 20-year government bond yield is artificially depressed and expected to increase, then the dividend yield is also artificially depressed and expected to increase. As a result, the results from the standard dividend discount models are likely to underestimate the cost of equity that will prevail going forward. While my estimates do not incorporate a quantification of the impact, the direction is clear – going forward, an increase in interest rates will likely lead to a higher dividend yield and, everything else equal, a higher estimated return on equity. This is especially true for the multi-stage DCF, where the growth rate originates from a mixture of company-specific growth and long-term GDP growth. The company-specific growth forecasts may have accounted for an expected decline in the P/E ratio, but there is no reason to believe the GDP growth rate takes this into account.

Q. What do you conclude from this information?

A. The increase in the spread between the yield on utility and government bonds indicates that the premium investors require to hold assets that are not risk-free has increased. Similarly, the forecasted MRP indicates an increase in investors risk premium. These factors point to investors' requiring a higher premium than historically to hold assets that are not risk-free. Similarly, the very low risk-free rate are likely to have led to higher P/E ratios due to the flight to quality discussed above and consequently a lower than "normal" dividend yields.

D. Impact on ROE estimation

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 program and efficient business operations, and 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 development in the risk-free rate and the current MRP.

These investors have been dramatically affected by the credit crisis and ongoing market volatility, so there are reasons to believe that their risk aversion remains elevated relative to pre-crisis periods.

Likewise, the effects of the Federal Reserve's monetary policy have artificially lowered the risk-free rate. As a result, yield spreads on utility debt, including top-rated instruments, have remained elevated. The evidence presented above demonstrates that the equity risk premium is higher today than it was prior to the crisis for all risky investments. This is true even for investments of lower-than-average risk, such as the equity of regulated utilities. As explained below my ROE estimates reflect this market evidence.

Q. Does your analysis consider the current economic conditions?

A. Yes. In implementing the risk premium model, I consider the impact of the downward bias in the current risk free rate as one scenario and also consider a scenario, which does not incorporate such bias. Similarly, I consider that the multi-stage DCF is likely downward biased and therefore recommend that weight be assigned to both the single-stage and multi-stage DCF.

IV. Estimating the Cost of Capital

A. Approach

Q. Please explain the process you used to estimate the cost of equity capital?

A. First, I select a sample of electric utilities, whose characteristics resemble those of PGE. 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. Finally, I check my recommendation against other measures such as the allowed return on equity for U.S. electric utilities.

Q. Please summarize each of the steps listed above.

A. To select a comparable sample of electric utilities, I look to the universe of publicly traded electric utilities as classified by the Value Line Investment Survey.[39] This resulted in an initial group of 45 companies. From this group, I kept those that meet the following criteria: (1) have five years of data available for examination, (2) have an investment grade rating, (3) have substantial regulated assets, and (4) have sufficient size such that market data are meaningful. I exclude companies with unique circumstances that may bias the cost of capital estimation such as substantial merger or acquisitions, recent dividend cuts or other unique factors.[40]

To estimate the cost of equity for the sample, I rely on two versions of the Discounted Cash Flow (DCF) model and the risk premium model. I further confirm these figures by comparing the estimates to the recently allowed ROE for electric utilities and to estimates

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[39] Value Line lists 48 companies as electric utilities, but 3 (AvanGrid, Wilmington Capital, ITC Holdings) do not operate electric distribution or generation. Thus, I examine only the 45 remaining companies.
[40] For example, I exclude both NextEra and Hawaiian Electric due to attempts by NextEra to acquire Hawaiian Electric.

obtained from two versions of the Capital Asset Pricing Model (CAPM). Specifically, I calculate the DCF cost of equity using the standard (single-stage) Gordon growth model and a three-stage DCF model. Further, I implement the risk premium model using authorized returns.

As noted above, the cost of equity capital for a company depends on its financial leverage. As the sample's DCF (and CAPM) measures of cost of equity were estimated using the sample companies' market value capital structure I determine the current capital structure (and the five-year average capital structure). I can then use these figures to convert the sample's cost of equity estimate to an estimate for PGE using its 50-50 capital structure. I then look to PGE's level of risk relative to the sample and consider PGE's smaller size and need to integrate substantial new generation in its portfolio. PGE has in recent years substantially increased its wind generation, put the 440 MW Carty plant into service in 2016, and expects additional capital expenditure spending in 2017.[41]

Finally, I consider the reasonableness of the estimated cost of equity for PGE in light of recently allowed ROE for electric utilities and in the light of the changing electric industry. For example, the electric industry is facing significant risk of competition from self-generation and a substantial change in the generation fleet, which may mean that historical measures of the cost of equity as reflected in a risk premium analysis may not be representative of the industry's cost of equity going forward.

B. Sample Selection

Q. Please describe how you selected your sample.

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[41] Portland General 2015 form 10-K, p. 15 shows a substantial increase in Portland General's wind generation and Portland General Electric, Investor Presentation December 2016.

A. To select a comparable sample of electric utilities, I began with the universe of publicly traded electric utilities as classified by Value Line.[42] This resulted in an initial group of 45 companies. From this group, I kept those that are Regulated (at least 80% of assets are regulated) or Mostly Regulated (50-79% of assets are regulated) as determined by EEI.[43] In addition, I require that the selected companies have five years of data available, an investment grade rating, and sufficient size that market data are meaningful. I exclude companies with unique circumstances that may bias the cost of capital estimation such as substantial merger or acquisitions, dividend cuts or other unique factors. Value Line companies that merged as well as entities with an acquisition or merger larger than 30% of their market capitalizations were excluded, as were entities that had announced dividend cuts or companies with non-investment grade bond ratings.

Q. Please summarize the characteristics of your sample.

A. The electric utilities sample is comprised of regulated companies whose primary source of revenues and majority of assets are in the regulated portion of the electric industry. The final sample consists of the 25 electric utilities listed in Table 2 below.

The 2015 annual revenue as well as the market cap were obtained from Bloomberg, as were the recent credit rating and growth estimates. Betas were obtained from Value Line.

[42] The 45 companies are from Value Line Investment Analyzer.
[43] *Edison Electric Institute* – Q2 2016 Rate Case Summary.

Table 2: Electric Sample and Its Characteristics[44]

U.S. Electric Sample

Company	DCF Subsample	Annual Revenues (USD million)	Regulated Assets	Market Cap. 2016 Q3 (USD million)	Betas	S&P Credit Rating (2016)	Long Term Growth Est.
	[2]	[3]	[4]	[5]	[6]	[7]	[8]
ALLETE		$1,379	M	$2,997	0.75	BBB+	4.7%
Alliant Energy	*	$3,263	R	$8,841	0.70	A-	6.3%
Amer. Elec. Power	*	$16,205	R	$32,042	0.65	BBB+	2.2%
Ameren Corp.	*	$6,028	R	$12,115	0.65	BBB+	5.7%
CenterPoint Energy		$7,238	M	$10,097	0.85	A-	6.6%
CMS Energy Corp.	*	$6,268	R	$11,917	0.65	BBB+	7.0%
Consol. Edison	*	$12,074	R	$23,296	0.55	A-	2.4%
Dominion Resources		$11,207	M	$47,252	0.65	BBB+	6.8%
DTE Energy	*	$10,243	R	$16,898	0.65	BBB+	5.9%
Edison Int'l		$11,325	R	$23,951	0.65	BBB+	3.4%
El Paso Electric	*	$876	R	$1,886	0.70	BBB	6.1%
Entergy Corp.	*	$10,706	R	$14,147	0.65	BBB+	-6.5%
IDACORP Inc.	*	$1,254	R	$3,961	0.75	BBB	3.9%
MGE Energy		$537	M	$1,975	0.70	AA-	6.5%
OGE Energy	*	$2,176	R	$6,386	0.90	A-	5.2%
Otter Tail Corp.	*	$796	R	$1,380	0.85	BBB	6.5%
PG&E Corp.	*	$17,120	R	$31,566	0.65	BBB+	6.7%
Pinnacle West Capital	*	$3,494	R	$8,563	0.70	A-	4.7%
Portland General	*	$1,898	R	$3,833	0.70	BBB	6.6%
PPL Corp.	*	$7,465	R	$23,739	0.70	A-	1.5%
Public Serv. Enterprise		$9,249	M	$21,487	0.70	BBB+	2.2%
SCANA Corp.		$4,126	M	$13,299	0.70	BBB+	5.7%
Sempra Energy		$10,014	M	$26,864	0.80	BBB+	9.5%
Vectren Corp.	*	$2,354	R	$4,156	0.75	A-	5.5%
Xcel Energy Inc.	*	$10,958	R	$21,240	0.60	A-	5.7%
Full Sample Average		**$6,730**		**$14,956**	**0.70**		**4.8%**
Subsample Average		**$6,657**		**$13,292**	**0.69**		**4.4%**

Notes: R – Regulated (at least 80% of assets are regulated), M (50-79% of assets are regulated). S&P Credit Ratings are from Research Insight as of 2016 Q3. Research Insight does not report S&P credit ratings for MGE Energy. I use the S&P ratings of MGEE's subsidiary, Madison Gas and Electric Company.

Q. How does the sample compare to PGE?

A. The sample was selected to consist of companies with more than 50% of their assets dedicated to regulated activities. As can be seen from Table 2, the majority of the sample companies are Regulated (meaning at least 80% of assets are rate regulated) as is PGE. The

[44] Sources: *Value Line Investment Survey* as of December 7, 2016, Bloomberg as of December 8, 2016, and *Edison Electric Institute* as of June 30, 2016. I note that relative to my prior testimony before the Commission, I have dropped Great Plains Energy and Westar Energy from my sample due to their merger announcement and have added PPL Corp., whose acquisition of Louisville Gas & Electric in 2010 by now should not influence data used in the estimation process.

average credit rating is higher than that of PGE at an average of BBB+, while PGE maintains a BBB rating from S&P (A- from Moody's). The majority of the companies are materially larger than PGE and only four companies have a market cap below that of PGE, Measured by beta, a measure of systematic risk, PGE is similar to the average of the sample, but its growth rate is more than a percentage point higher.

C. Capital Structure

Q. What regulatory capital structure is PGE requesting in this proceeding?

A. PGE has requested a regulatory capital structure consisting of 50% equity and 50% debt,[45] which was also the capital structure used in the UE 294 proceeding.[46] This capital structure is broadly consistent with the book value capital structures of the sample companies. The sample averages about 47% equity on a book basis. The highest percentage of book equity for the companies in the sample is 65% equity (MGE Energy Inc.) and the lowest is 29% equity (CenterPoint Energy).[47] However, the market based estimates of the cost of equity for the DCF are based on the market value capital structure, which include 59.5% equity as of Q3, 2016.[48] My recommended range for ROE is a function of the requested capital structure, the sample average cost of capital estimates and the relative risk of PGE compared to the sample.

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[45] The calculation of the capital structure is available in PGE Exhibit 1000.
[46] Order 14-442, issued December 4, 2014, p. 3.
[47] See PGE Exhibit 1101.
[48] The CAPM would use a five-year average to be consistent with the beta estimate. The five-year average is lower at approximately 56% equity.

V. Cost of Capital Estimates

Q. How do you estimate the sample companies' costs of equity?

A. As noted earlier, I employ three general methodologies: Discounted Cash Flow (DCF), Capital Asset Pricing Models (CAPM), and risk premium models. All methods are commonly used in U.S. state regulatory proceedings and have been presented to the Commission previously by PGE. For the DCF estimates, I present two models: the standard Gordon growth model (or the single-stage DCF) and a three-stage DCF model. I implement the three-stage DCF model using two different long-term growth rates: the consensus Blue Chip forecast and an average of the estimate from OMB and Blue Chip. Further, I estimate the ROE from a version of the risk premium method: a regression analysis of allowed return on bond rates. Finally, I estimate two versions of the CAPM as a check on my results: the traditional CAPM and two versions of the Empirical CAPM.[49] Because the cost of equity cannot be measured precisely, it is important to consider more than one method. Further, each method has its strengths and weaknesses, which may be more or less prevalent at any given time. It is therefore necessary to evaluate the estimated cost of equity in the light of the prevalent market conditions and the relative strengths and weaknesses of the model to take these factors into account. I also cross-check my estimates against recently allowed ROEs in other jurisdictions although I do not use this as an input to my recommendation.

[49] The CAPM is a commonly used cost of capital estimation model in corporate finance and I usually include it among my methods. However, the Commission has historically not relied upon the CAPM, so I present it only as a check on other results in this proceeding.

A. The DCF Based Estimates

Q. Please describe the discounted cash flow approach to estimating the cost of equity.

A. The DCF model takes the first approach to cost of capital estimation described above, i.e., to attempt to estimate the cost of capital in one step instead of estimating the cost of capital for the entire market and then determining the cost of capital for an individual investment. The DCF method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P = \frac{D_1}{(1+r)} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \quad (2)$$

where "P" is the market price of the stock; "D_i" is the dividend cash flow expected at the end of period i; "r" is the cost of capital; and "T" is the last period in which a dividend cash flow is to be received. The formula just 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.

The standard DCF application goes on to make the assumption that the growth rate remains constant forever, which simplifies the standard formula, so that it can be rearranged to estimate the cost of capital. 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 the formula,

$$P = \frac{D_1}{(r-g)} \quad (3)$$

where "D_1" is the dividend expected at the end of the first period, "g" is the perpetual growth rate, and "P" and "r" are the market price and the cost of capital, as before.

Equation (3) is a simplified version of equation (2) that can be solved to yield the well-known "DCF formula" for the cost of capital:

$$\begin{aligned} r &= \frac{D_1}{P} + g \\ &= \frac{D_0 \times (1+g)}{P} + g \end{aligned} \tag{4}$$

where "D_0" is the current dividend, which investors expect to increase at rate g by the end of the next period, and the other symbols are defined as before. 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 Gordon DCF model.

Q. Are there models other than the Gordon DCF model?

A. Yes. There are many alternatives, notably, (i) multi-stage models and (ii) models that use cash flow rather than dividends or combinations of (i) and (ii).[50] One such alternative expands the Gordon DCF model to three stages.[51] 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.

Q. What is your assessment of the DCF model?

A. The DCF approach is grounded in solid financial theory. It is widely accepted by regulatory commissions and provides useful insight regarding the cost of capital based on forward-looking metrics. DCF estimates of the cost of capital complement those of the Risk Premium or CAPM because the methods rely on different inputs and assumptions. The DCF

[50] The Surface Transportation Board uses a cash flow based model with three stages. See, for example, Surface Transportation Board, "Ex Parte No. 664 (Sub-No. 1)," Issued January 23, 2009. Confirmed in EP 664 (Sub-No. 2), issued October 31, 2016.

[51] I note that because investors are interested in cash flow, it is technically important to include all cash flow that is distributed to shareholders. Notably, many companies distribute cash through share buybacks in addition to dividends and therefore, I would include this type of distribution. However, among the comparable companies only El Paso Electric has non-trivial share buybacks and including the amount would not affect the results. Therefore, I ignore this aspect for this proceeding.

method is particularly valuable in the current economic environment, because of the effects on capital market conditions of the Fed's efforts to maintain interest rates at historically low levels which bias the Risk Premium (and CAPM-based) estimates downward.

However, I recognize that the DCF model, like most models, relies upon assumptions that do not always correspond to reality. This is why the reliance on multiple methods is important.

Q. What growth rate information do you use?

A. The first step in my DCF analysis (either constant growth or multistage formulations) is to examine a sample of investment analysts' forecasted earnings growth rates from Bloomberg and from Value Line for companies in the electric sample. For the long-term growth rate for the final, constant-growth stage of the multistage DCF estimates, I use two estimates: (i) the most recent long-run GDP growth forecast from Blue Chip Economic Indicators and (ii) the average of the OMB and Blue Chip long-term estimate.[52]

Q. How do these growth rates correspond to the theoretical criteria you discuss above?

A. The constant-growth formulation of the DCF model, in principle, requires forecasted growth rates, but it is also necessary that the growth rates used extend far enough into the future so that it is reasonable to believe that investors expect a stable growth path afterwards. Under current economic conditions, I believe the forecasted growth rates of investment analysts provide the best available representation of the longer term, steady-state growth rate expectations of investors.

Q. Does the multistage DCF improve upon the simple DCF?

[52] *Blue Chip Economic Indicators*, October 10, 2016 and the Fiscal Year 2017 Budget Forecast, March 2016. The latter has in the past been one of the estimates relied upon by Commission Staff.

A. Potentially, but the multistage method assumes a particular smoothing pattern and a long-term growth rate afterwards. These assumptions may not be a more accurate representation of investor expectation than those of the simple DCF. The smoother growth pattern, for example, might not be representative of investor expectations, in which case the multistage model would not increase the accuracy of the estimates. Indeed, amidst uncertainty in capital markets, assuming a simple constant growth rate may be preferable to attempting to model growth patterns in greater detail over multiple stages. While it is difficult to determine which set of assumptions comprises a closer approximation of the actual conditions of capital markets, I believe both forms of the DCF model provide useful information about the cost of capital.

Q. What are your DCF estimates?

A. Looking at the full sample, the ROE estimate is 10.3% for the Gordon (single-stage) DCF model and 9.1% for the multistage model using the average of the Blue Chip and OMB growth forecast. Table 3 below summarizes the results from the DCF models.

Table 3: DCF Estimates on the Cost of Equity

Single-stage	10.3%
Multi-stage using Blue Chip GDP growth:	9.0%
Multi-stage using average of Blue Chip and OMB GDP growth:	9.1%

Q. Do you have any comments on the DCF estimates?

A. Yes. The multi-stage DCF estimates may well be downward biased as they rely on a combination of the long-term GDP growth and a contemporaneous price-earnings ratio. As indicated in Figure 6 above, the P/E ratio tends to decline as interest rates increase.

Therefore, given the expected increase in interest rates, the P/E ratio may be overstated and thus the dividend yield is understated. As shown above, the impact on the dividend yield of a 1% increase in the risk-free rate is approximately 43 basis points. As interest rates are expected to increase by more than 50 basis points, the dividend yield would increase by a bit more than 20 basis points.[53] Thus, the DCF estimates are likely too low and expected to increase going forward. This is especially true for the multi-stage DCF, where company-specific growth rates are not reflecting the current dividend yield, but the market as a whole.

Q. What conclusions do you draw from the DCF analysis?

A. The estimate from the multi-stage model using a combined Blue Chip or a combined Blue Chip and OMB growth rate is too low to be consistent with the cost of equity for 2018 and I recommend using a DCF measure that puts substantial weight on the Gordon growth model estimate or relying on the midpoint of all estimates. Regardless, I find that a reasonable DCF estimate for the sample is 9.7% to 9.9%, where the 9.7% is calculated as the midpoint of the single-stage and multi-stage DCF and the 9.9% is the midpoint plus 20 basis points, where the 20 basis points are calculated above. Noting that PGE is expecting larger growth than the average sample company, high capex, and is smaller than the average sample company, the DCF estimates are on the low end of what is reasonable for PGE.

[53] The Blue Chip forecasts the 10-year government bond yield at 2.8% for 2018. Adding the historical maturity premium of about 0.54% to that figure, the forecasted 20-year government bond yield is 3.34%. As the 15-day average 20-year bond yield as of December 6, 2016 was 2.71%, the increase is 0.63%. I rounded these figures downward in the calculation above.

B. Risk Premium Methods

Q. Do you estimate the Cost of Equity that result from risk premium analysis?

A. Yes, I estimate the risk premium using a statistical regression approach. Specifically, I calculate the statistical relationship between the allowed ROE for electric utilities and the 20-year government bond rate using quarterly data. This results in an estimated ROE of 9.9% to 10.4% for 2018.

Q. Please explain the implementation and data underlying your risk premium analysis.

A. Using quarterly data from Regulatory Research Associates from Q1 1990 to Q3 2016,[54] I estimate the equation:

$$\text{Risk Premium} = A_0 + (A_1 \times \text{Treasury Bond Yield})$$

The equation is estimated using ordinary least squares and the parameters are statistically significant (details are in PGE Exhibit 1102). Using this approach, I estimate a risk premium of 6.54%, which is then added to the forecasted 20-year yield in 2018 as PGE's rates are expected to go into effect then. *I.e.,*

$$\text{Estimated ROE} = \text{Forecast Risk-Free Rate} + \text{Risk Premium}$$

The forecasted 20-year yield is 3.34% if currently elevated yield spread is not taken into account and 3.89% if the elevated yield spread is assumed to remain.[55] Using these two forecasts for the risk-free rate, I obtain cost of equity estimates of 9.9% and 10.4%, respectively. Because it is plausible that the yield spread will moderate as the government bond yield increases, I consider the midpoint of 10.15% to be a reasonable point estimate. This estimate is also consistent with recently allowed ROEs once the likely increase in interest rates is considered. Electric utility authorized ROEs for the first three quarters

[54] SNL Financial as of December 12, 2016.
[55] *Blue Chip Economic Indicators Forecast*, October 2016.

averaged 9.91%[56] and if interest rates are expected to increase by about 40 basis points to 2018, plausibly allowed ROEs will also increase.[57]

Table 4: Risk Premium Estimate on the Cost of Equity

Risk Premiums Determined by Relationship Between Authorized ROEs[1] and Long-term Treasury Bond Rates During the Period 1990-2016

Equity Cost Estimate for Vertically Integrated Electric		Predicted Risk Premium		Expected Treasury Bond Rate[2]	
10.4%	=	6.54%	+	3.89%	[3]
9.9%	=	6.54%	+	3.34%	[4]

Sources and Notes:
[1]: Authorized ROE Data sourced from SNL Financial.
[2]: Blue Chip consensus forecast 2018 10-yr T-bill Yield plus maturity premium
[3]: Estimate with expected treasury bond rate normalized with 0.55% utility yield spread adjustment
[4]: Estimate without treasury bond rate normalization.
See regression results for derivation of regression coefficients A_0 and A_1.

Q. Is this estimate consistent with PGE's regulatory capital structure of 50% equity and 50% debt?

A. Yes, the authorized ROE pertains to the regulated capital structure of the entities for which state regulatory commissions allowed an ROE. The regulatory capital structures generally contain 48% to 52% equity with an average of near 50% equity in the last few years.[58] Therefore, the estimated ROE is consistent with PGE's capital structure.

Q. What conclusions do you draw from the analysis?

[56] Regulatory Research Associates, "Major Rate Case Decisions – January – September 2016," October 14, 2016.
[57] During Q3, 2016, the average allowed ROE was 9.76% according to Regulatory Research Associates, "Major Rate Case Decisions – January – September 2016," October 14, 2016.
[58] SNL Financial as of December 12, 2016.

A. The risk premium analysis results in an ROE estimate that is consistent with the single-stage DCF results as well as with the upper end of my CAPM results. I therefore find that PGE's requested ROE of 9.75% is not just reasonable, but conservative.

Q. Is there other relevant evidence regarding the current cost of equity for electric utilities?

A. Yes, looking at the recently authorized ROE for regulated electric utilities, I find a range of 9.37 to 10.55% for 2016 if I ignore the generation incentives provided in Virginia. The average for all electric utilities was 9.91%, which is higher than PGE's request.[59] Finally, I estimate the cost of equity using the Capital Asset Pricing Model, which determines the cost of equity as follows:

$$r_S = r_f + \beta_S \times MRP$$

Where r_s is the cost of capital for investment *S*; r_f is the risk-free rate; β_S is the beta risk measure for the investment *S*; and *MRP* is the market risk premium. The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities. I estimate this model using Value Line betas, the risk-free rate that Blue Chip forecasts for 2018 (as in the risk-premium analyses above), and the historical MRP for the period 1926-2015 as reported by the 2016 Duff & Phelps Valuation Handbook.[60] I also implement two variations of the model that relies on the empirical observation that the intercept in Figure 1 is higher than in the theoretical CAPM, but the slope is lower. The CAPM and the empirical CAPM results in cost of equity estimates in the range of 9.3% to 10.2% for the full sample and

[59] Regulatory Research Associates, "Major Rate Case Decisions – January – September 2016," October 14, 2016.
[60] *Blue Chip Economic Indicators*, October 2016; Duff & Phelps, 2016 Valuation Handbook, Guide to Cost of Capital, page 3-24.

9.2% to 10.1% for the subsample, which confirms that PGE's requested ROE of 9.75% is reasonable. The details of this model are in PGE Exhibits 1103 and 1104.

VI. Conclusions

Q. Please summarize the evidence from the sample regarding the ROE for an electric utility of average risk?

A. Tables 3 and 4 summarize the results of the analyses for the DCF and risk premium models for the sample of electric utilities. The results from the CAPM and risk premium models are within the range obtained from the DCF models. As a result, the overall range of cost of equity estimates is 9.3% to 10.3% using the full sample and ignoring the lowest and highest estimate, so that the midpoint is 9.8%. This range is consistent with the DCF results as well as with recently authorized ROEs for U.S. electric utilities.

Overall, I believe PGE's request for an ROE of 9.75% is reasonable albeit conservative.

VII. Qualifications

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 (BS and MS) 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 rail road 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 more detailed resume is PGE Exhibit 1108.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1101	DCF Estimates
1102	Risk Premium Analysis
1103	The CAPM Description
1104	The CAPM Estimates
1105	Authorized ROE for Integrated Electric Utilities in 2016
1106	Yield Spreads
1107	P/E and Payout Ratios
1108	Resume for Bente Villadsen

EXHIBIT PGE 1101

CAPITAL STRUCTURE

DCF COST OF EQUITY

Table No. BV-ELEC-2

Classification of Companies by Assets

Company	Company Category
ALLETE	M
Alliant Energy	R
Amer. Elec. Power	R
Ameren Corp.	R
CenterPoint Energy	M
CMS Energy Corp.	R
Consol. Edison	R
Dominion Resources	M
DTE Energy	R
Edison Int'l	R
El Paso Electric	R
Entergy Corp.	R
IDACORP Inc.	R
MGE Energy	M
OGE Energy	R
Otter Tail Corp.	R
PG&E Corp.	R
Pinnacle West Capital	R
Portland General	R
PPL Corp.	R
Public Serv. Enterprise	M
SCANA Corp.	M
Sempra Energy	M
Vectren Corp.	R
Xcel Energy Inc.	R

Sources and Notes:
Percent regulated categories and company data are based on Edison Electric Institute: "Rate Case Summary - Q1 2016 Financial Update".
R = Regulated (greater than 80 percent of total assets are regulated).
M = Mostly Regulated (50 to 80 percent of total assets are regulated).
D = Diversified (less than 50 percent of total assets are regulated).

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel A: ALLETE

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$1,873	$1,873	$1,822	$1,529	$1,288	$1,158	$1,051	[a]
Shares Outstanding (in millions) - Common	50	50	49	45	41	39	37	[b]
Price per Share - Common	$62	$61	$49	$46	$48	$42	$38	[c]
Market Value of Common Equity	$3,087	$2,997	$2,393	$2,048	$1,941	$1,616	$1,384	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$3,087	$2,997	$2,393	$2,048	$1,941	$1,616	$1,384	[f]= [d]
Market to Book Value of Common Equity	1.65	1.60	1.31	1.34	1.51	1.40	1.32	[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	$362	$362	$403	$358	$369	$278	$303	[j]
Current Liabilities	$404	$404	$318	$287	$224	$215	$122	[k]
Current Portion of Long-Term Debt	$187	$187	$49	$85	$38	$67	$13	[l]
Net Working Capital	$144	$144	$135	$156	$183	$131	$194	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$3	$1	$0	$6	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,359	$1,359	$1,549	$1,289	$1,064	$948	$844	[p]
Book Value of Long-Term Debt	$1,546	$1,546	$1,598	$1,375	$1,102	$1,015	$857	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,676	$1,676	$1,485	$1,132	$1,144	$966	$797	
Carrying Amount	$1,605	$1,605	$1,374	$1,110	$1,018	$863	$785	
Adjustment to Book Value of Long-Term Debt	$71	$71	$111	$22	$126	$103	$12	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,617	$1,617	$1,709	$1,396	$1,228	$1,118	$869	[s] = [q] + [r].
Market Value of Debt	$1,617	$1,617	$1,709	$1,396	$1,228	$1,118	$869	[t] = [s].
MARKET VALUE OF FIRM	$4,704	$4,614	$4,102	$3,444	$3,169	$2,734	$2,253	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	65.63%	64.96%	58.33%	59.47%	61.26%	59.11%	61.43%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	34.37%	35.04%	41.67%	40.53%	38.74%	40.89%	38.57%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel B: Alliant Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$3,859	$3,859	$3,745	$3,436	$3,267	$3,116	$3,002	[a]
Shares Outstanding (in millions) - Common	228	228	227	222	222	222	222	[b]
Price per Share - Common	$36	$39	$28	$28	$25	$22	$20	[c]
Market Value of Common Equity	$8,225	$8,841	$6,434	$6,291	$5,494	$4,871	$4,340	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$8,225	$8,841	$6,434	$6,291	$5,494	$4,871	$4,340	[f]= [d]
Market to Book Value of Common Equity	2.13	2.29	1.72	1.83	1.68	1.56	1.45	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$200	$200	$200	$200	$200	$205	$205	[h]
Market Value of Preferred Equity	$200	$200	$200	$200	$200	$205	$205	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$958	$958	$1,088	$962	$880	$1,029	$947	[j]
Current Liabilities	$1,370	$1,370	$991	$1,742	$1,053	$946	$774	[k]
Current Portion of Long-Term Debt	$314	$314	$3	$493	$48	$1	$1	[l]
Net Working Capital	($98)	($98)	$100	($287)	($124)	$84	$174	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$238	$238	$109	$354	$237	$70	$22	[n]
Adjusted Short-Term Debt	$98	$98	$0	$287	$124	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$3,817	$3,817	$3,856	$2,800	$3,105	$2,828	$2,704	[p]
Book Value of Long-Term Debt	$4,229	$4,229	$3,859	$3,579	$3,278	$2,830	$2,705	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$4,336	$4,336	$4,418	$3,712	$3,861	$3,325	$2,959	
Carrying Amount	$3,836	$3,836	$3,790	$3,336	$3,138	$2,705	$2,705	
Adjustment to Book Value of Long-Term Debt	$501	$501	$629	$376	$722	$621	$254	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$4,729	$4,729	$4,487	$3,955	$4,000	$3,450	$2,959	[s] = [q] + [r].
Market Value of Debt	$4,729	$4,729	$4,487	$3,955	$4,000	$3,450	$2,959	[t] = [s].
MARKET VALUE OF FIRM	$13,154	$13,770	$11,121	$10,446	$9,694	$8,526	$7,504	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	62.53%	64.21%	57.85%	60.22%	56.68%	57.13%	57.84%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	1.52%	1.45%	1.80%	1.91%	2.06%	2.41%	2.73%	[w] = [i] / [u].
Debt - Market Value Ratio	35.95%	34.34%	40.35%	37.86%	41.26%	40.47%	39.43%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel C: Amer. Elec. Power

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$17,322	$17,322	$17,699	$16,868	$15,762	$15,306	$14,653	[a]
Shares Outstanding (in millions) - Common	492	492	491	489	487	485	483	[b]
Price per Share - Common	$59	$65	$55	$53	$43	$44	$38	[c]
Market Value of Common Equity	$29,224	$32,042	$27,037	$25,812	$21,167	$21,277	$18,174	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$29,224	$32,042	$27,037	$25,812	$21,167	$21,277	$18,174	[f]= [d]
Market to Book Value of Common Equity	1.69	1.85	1.53	1.53	1.34	1.39	1.24	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$60	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$60	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$5,949	$5,949	$4,548	$4,111	$4,317	$4,648	$4,374	[j]
Current Liabilities	$7,779	$7,779	$7,058	$7,457	$5,692	$6,795	$5,684	[k]
Current Portion of Long-Term Debt	$2,385	$2,385	$1,826	$2,381	$1,366	$2,272	$1,267	[l]
Net Working Capital	$555	$555	($684)	($965)	($9)	$125	($43)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,478	$1,478	$782	$1,282	$1,218	$1,216	$1,279	[n]
Adjusted Short-Term Debt	$0	$0	$684	$965	$9	$0	$43	[o] = See Sources and Notes.
Long-Term Debt	$17,320	$17,320	$17,600	$15,677	$16,202	$14,955	$15,183	[p]
Book Value of Long-Term Debt	$19,705	$19,705	$20,110	$19,023	$17,577	$17,227	$16,493	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$21,201	$21,201	$21,075	$19,672	$20,907	$19,259	$18,285	
Carrying Amount	$19,573	$19,573	$18,684	$18,377	$17,757	$16,516	$16,811	
Adjustment to Book Value of Long-Term Debt	$1,629	$1,629	$2,391	$1,295	$3,150	$2,743	$1,474	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$21,333	$21,333	$22,501	$20,318	$20,727	$19,970	$17,967	[s] = [q] + [r].
Market Value of Debt	$21,333	$21,333	$22,501	$20,318	$20,727	$19,970	$17,967	[t] = [s].
MARKET VALUE OF FIRM	$50,558	$53,375	$49,538	$46,130	$41,894	$41,247	$36,201	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	57.80%	60.03%	54.58%	55.95%	50.53%	51.58%	50.20%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	0.17%	[w] = [i] / [u].
Debt - Market Value Ratio	42.20%	39.97%	45.42%	44.05%	49.47%	48.42%	49.63%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel D: Ameren Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$7,193	$7,193	$7,014	$6,774	$6,574	$7,874	$7,997	[a]
Shares Outstanding (in millions) - Common	243	243	243	243	243	243	242	[b]
Price per Share - Common	$49	$50	$40	$38	$34	$33	$30	[c]
Market Value of Common Equity	$11,926	$12,115	$9,802	$9,318	$8,311	$7,920	$7,286	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$11,926	$12,115	$9,802	$9,318	$8,311	$7,920	$7,286	[f]= [d]
Market to Book Value of Common Equity	1.66	1.68	1.40	1.38	1.26	1.01	0.91	[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	$1,599	$1,599	$1,983	$1,942	$3,273	$2,406	$2,680	[j]
Current Liabilities	$2,291	$2,291	$2,489	$2,119	$3,228	$1,546	$1,848	[k]
Current Portion of Long-Term Debt	$431	$431	$395	$119	$884	$206	$178	[l]
Net Working Capital	($261)	($261)	($111)	($58)	$929	$1,066	$1,010	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$608	$608	$783	$753	$0	$5	$350	[n]
Adjusted Short-Term Debt	$261	$261	$111	$58	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$6,607	$6,607	$5,981	$5,825	$5,274	$6,781	$6,682	[p]
Book Value of Long-Term Debt	$7,299	$7,299	$6,487	$6,002	$6,158	$6,987	$6,860	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$7,814	$7,814	$7,135	$6,584	$7,110	$7,800	$7,661	
Carrying Amount	$7,275	$7,275	$6,240	$6,038	$6,157	$6,856	$7,008	
Adjustment to Book Value of Long-Term Debt	$539	$539	$895	$546	$953	$944	$653	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$7,838	$7,838	$7,382	$6,548	$7,111	$7,931	$7,513	[s] = [q] + [r].
Market Value of Debt	$7,838	$7,838	$7,382	$6,548	$7,111	$7,931	$7,513	[t] = [s].
MARKET VALUE OF FIRM	$19,764	$19,953	$17,184	$15,866	$15,422	$15,851	$14,799	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	60.34%	60.72%	57.04%	58.73%	53.89%	49.97%	49.23%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	39.66%	39.28%	42.96%	41.27%	46.11%	50.03%	50.77%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel E: CenterPoint Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$3,472	$3,472	$4,058	$4,473	$4,261	$4,257	$4,207	[a]
Shares Outstanding (in millions) - Common	431	431	430	430	429	427	426	[b]
Price per Share - Common	$24	$23	$18	$24	$24	$21	$20	[c]
Market Value of Common Equity	$10,255	$10,097	$7,692	$10,424	$10,139	$8,997	$8,331	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$10,255	$10,097	$7,692	$10,424	$10,139	$8,997	$8,331	[f]= [d]
Market to Book Value of Common Equity	2.95	2.91	1.90	2.33	2.38	2.11	1.98	[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	$2,529	$2,529	$2,400	$2,576	$2,319	$2,752	$1,982	[j]
Current Liabilities	$2,398	$2,398	$3,191	$3,008	$2,595	$3,364	$2,319	[k]
Current Portion of Long-Term Debt	$772	$772	$938	$722	$553	$1,402	$483	[l]
Net Working Capital	$903	$903	$147	$290	$277	$790	$146	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$43	$43	$49	$80	$70	$53	$84	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$7,736	$7,736	$7,662	$7,797	$7,758	$8,415	$8,497	[p]
Book Value of Long-Term Debt	$8,508	$8,508	$8,600	$8,519	$8,311	$9,817	$8,980	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$9,101	$9,101	$9,427	$8,670	$10,807	$10,049	$10,071	
Carrying Amount	$8,620	$8,620	$8,652	$8,171	$9,619	$8,994	$9,303	
Adjustment to Book Value of Long-Term Debt	$481	$481	$775	$499	$1,188	$1,055	$768	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$8,989	$8,989	$9,375	$9,018	$9,499	$10,872	$9,748	[s] = [q] + [r].
Market Value of Debt	$8,989	$8,989	$9,375	$9,018	$9,499	$10,872	$9,748	[t] = [s].
MARKET VALUE OF FIRM	$19,244	$19,086	$17,067	$19,442	$19,638	$19,869	$18,079	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	53.29%	52.90%	45.07%	53.62%	51.63%	45.28%	46.08%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	46.71%	47.10%	54.93%	46.38%	48.37%	54.72%	53.92%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel F: CMS Energy Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$4,259	$4,259	$3,902	$3,670	$3,396	$3,196	$3,043	[a]
Shares Outstanding (in millions) - Common	279	279	277	275	266	264	252	[b]
Price per Share - Common	$40	$43	$34	$30	$26	$23	$20	[c]
Market Value of Common Equity	$11,252	$11,917	$9,338	$8,161	$7,018	$6,141	$4,997	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$11,252	$11,917	$9,338	$8,161	$7,018	$6,141	$4,997	[f]= [d]
Market to Book Value of Common Equity	2.64	2.80	2.39	2.22	2.07	1.92	1.64	[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	$2,198	$2,198	$2,123	$2,734	$2,401	$2,360	$2,860	[j]
Current Liabilities	$2,069	$2,069	$1,788	$1,648	$1,464	$1,485	$2,214	[k]
Current Portion of Long-Term Debt	$1,005	$1,005	$741	$690	$532	$510	$1,140	[l]
Net Working Capital	$1,134	$1,134	$1,076	$1,776	$1,469	$1,385	$1,786	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$75	$75	$68	$0	$0	$0	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$8,832	$8,832	$8,014	$8,171	$7,229	$6,866	$6,208	[p]
Book Value of Long-Term Debt	$9,837	$9,837	$8,755	$8,861	$7,761	$7,376	$7,348	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$9,599	$9,599	$9,285	$8,368	$8,347	$8,025	$7,861	
Carrying Amount	$9,125	$9,125	$8,535	$7,642	$7,229	$7,073	$7,174	
Adjustment to Book Value of Long-Term Debt	$474	$474	$750	$726	$1,118	$952	$687	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$10,311	$10,311	$9,505	$9,587	$8,879	$8,328	$8,035	[s] = [q] + [r].
Market Value of Debt	$10,311	$10,311	$9,505	$9,587	$8,879	$8,328	$8,035	[t] = [s].
MARKET VALUE OF FIRM	$21,563	$22,228	$18,843	$17,748	$15,897	$14,469	$13,032	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	52.18%	53.61%	49.56%	45.98%	44.15%	42.44%	38.34%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	47.82%	46.39%	50.44%	54.02%	55.85%	57.56%	61.66%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel G: Consol. Edison

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$14,267	$14,267	$13,040	$12,707	$12,166	$11,842	$11,454	[a]
Shares Outstanding (in millions) - Common	305	305	293	293	293	293	293	[b]
Price per Share - Common	$70	$76	$65	$57	$56	$60	$57	[c]
Market Value of Common Equity	$21,437	$23,296	$18,927	$16,614	$16,301	$17,522	$16,659	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$21,437	$23,296	$18,927	$16,614	$16,301	$17,522	$16,659	[f]= [d]
Market to Book Value of Common Equity	1.50	1.63	1.45	1.31	1.34	1.48	1.45	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$213	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$213	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,154	$3,154	$3,505	$3,519	$3,704	$3,240	$3,458	[j]
Current Liabilities	$3,591	$3,591	$4,429	$3,873	$4,373	$3,724	$2,959	[k]
Current Portion of Long-Term Debt	$346	$346	$761	$210	$483	$930	$305	[l]
Net Working Capital	($91)	($91)	($163)	($144)	($186)	$446	$804	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$601	$601	$1,160	$1,425	$1,220	$340	$0	[n]
Adjusted Short-Term Debt	$91	$91	$163	$144	$186	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$13,747	$13,747	$11,521	$10,986	$10,495	$9,841	$10,371	[p]
Book Value of Long-Term Debt	$14,184	$14,184	$12,445	$11,340	$11,164	$10,771	$10,676	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$13,856	$13,856	$13,998	$12,082	$12,935	$12,744	$11,761	
Carrying Amount	$12,745	$12,745	$12,191	$10,974	$10,768	$10,673	$10,676	
Adjustment to Book Value of Long-Term Debt	$1,111	$1,111	$1,807	$1,108	$2,167	$2,071	$1,085	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$15,295	$15,295	$14,252	$12,448	$13,331	$12,842	$11,761	[s] = [q] + [r].
Market Value of Debt	$15,295	$15,295	$14,252	$12,448	$13,331	$12,842	$11,761	[t] = [s].
MARKET VALUE OF FIRM	$36,732	$38,591	$33,179	$29,062	$29,632	$30,364	$28,633	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.36%	60.37%	57.05%	57.17%	55.01%	57.71%	58.18%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	0.74%	[w] = [i] / [u].
Debt - Market Value Ratio	41.64%	39.63%	42.95%	42.83%	44.99%	42.29%	41.07%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel H: Dominion Resources

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$14,958	$14,958	$12,592	$11,573	$11,242	$11,818	$11,632	[a]
Shares Outstanding (in millions) - Common	627	627	595	584	580	575	570	[b]
Price per Share - Common	$73	$75	$69	$69	$62	$53	$50	[c]
Market Value of Common Equity	$45,702	$47,252	$41,040	$40,119	$35,768	$30,376	$28,377	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$45,702	$47,252	$41,040	$40,119	$35,768	$30,376	$28,377	[f]= [d]
Market to Book Value of Common Equity	3.06	3.16	3.26	3.47	3.18	2.57	2.44	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$134	$257	$257	$257	[h]
Market Value of Preferred Equity	$0	$0	$0	$134	$257	$257	$257	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,799	$3,799	$4,123	$5,446	$5,210	$4,653	$5,267	[j]
Current Liabilities	$9,027	$9,027	$6,746	$7,579	$6,453	$6,562	$5,496	[k]
Current Portion of Long-Term Debt	$2,931	$2,931	$1,528	$1,591	$1,132	$2,175	$1,327	[l]
Net Working Capital	($2,297)	($2,297)	($1,095)	($542)	($111)	$266	$1,098	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$3,097	$3,097	$2,555	$2,629	$2,145	$1,382	$783	[n]
Adjusted Short-Term Debt	$2,297	$2,297	$1,095	$542	$111	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$28,707	$28,707	$23,245	$20,666	$18,548	$17,144	$17,153	[p]
Book Value of Long-Term Debt	$33,935	$33,935	$25,868	$22,799	$19,791	$19,319	$18,480	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$23,210	$23,210	$21,881	$19,887	$19,898	$18,936	$16,112	
Carrying Amount	$21,998	$21,998	$19,723	$18,396	$16,841	$16,264	$14,520	
Adjustment to Book Value of Long-Term Debt	$1,212	$1,212	$2,158	$1,491	$3,057	$2,672	$1,592	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$35,147	$35,147	$28,026	$24,290	$22,848	$21,991	$20,072	[s] = [q] + [r].
Market Value of Debt	$35,147	$35,147	$28,026	$24,290	$22,848	$21,991	$20,072	[t] = [s].
MARKET VALUE OF FIRM	$80,849	$82,399	$69,066	$64,543	$58,873	$52,624	$48,706	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.53%	57.35%	59.42%	62.16%	60.75%	57.72%	58.26%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	0.21%	0.44%	0.49%	0.53%	[w] = [i] / [u].
Debt - Market Value Ratio	43.47%	42.65%	40.58%	37.63%	38.81%	41.79%	41.21%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel I: DTE Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$9,130	$9,130	$8,812	$8,169	$7,876	$7,389	$6,970	[a]
Shares Outstanding (in millions) - Common	179	179	179	177	177	172	169	[b]
Price per Share - Common	$94	$94	$78	$76	$67	$59	$49	[c]
Market Value of Common Equity	$16,897	$16,898	$13,951	$13,475	$11,792	$10,192	$8,372	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$16,897	$16,898	$13,951	$13,475	$11,792	$10,192	$8,372	[f]= [d]
Market to Book Value of Common Equity	1.85	1.85	1.58	1.65	1.50	1.38	1.20	[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	$2,595	$2,595	$2,700	$2,755	$2,549	$2,730	$2,911	[j]
Current Liabilities	$1,969	$1,969	$2,273	$2,805	$3,008	$2,309	$2,100	[k]
Current Portion of Long-Term Debt	$15	$15	$468	$274	$896	$633	$247	[l]
Net Working Capital	$641	$641	$895	$224	$437	$1,054	$1,058	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$410	$410	$185	$653	$271	$98	$275	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$9,478	$9,478	$8,856	$7,909	$6,846	$7,120	$7,497	[p]
Book Value of Long-Term Debt	$9,493	$9,493	$9,324	$8,183	$7,742	$7,753	$7,744	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$9,835	$9,835	$9,503	$8,475	$8,893	$8,757	$8,500	
Carrying Amount	$9,285	$9,285	$8,606	$8,094	$7,813	$7,682	$8,000	
Adjustment to Book Value of Long-Term Debt	$550	$550	$897	$381	$1,080	$1,075	$500	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$10,043	$10,043	$10,221	$8,564	$8,822	$8,828	$8,244	[s] = [q] + [r].
Market Value of Debt	$10,043	$10,043	$10,221	$8,564	$8,822	$8,828	$8,244	[t] = [s].
MARKET VALUE OF FIRM	$26,940	$26,941	$24,172	$22,039	$20,614	$19,020	$16,616	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	62.72%	62.72%	57.71%	61.14%	57.20%	53.59%	50.38%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	37.28%	37.28%	42.29%	38.86%	42.80%	46.41%	49.62%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel J: Edison Int'l

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY								
	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$11,814	$11,814	$11,600	$10,736	$9,689	$10,023	$11,015	[a]
Shares Outstanding (in millions) - Common	326	326	326	326	326	326	326	[b]
Price per Share - Common	$69	$74	$61	$57	$46	$45	$37	[c]
Market Value of Common Equity	$22,626	$23,951	$19,740	$18,584	$14,938	$14,719	$12,158	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$22,626	$23,951	$19,740	$18,584	$14,938	$14,719	$12,158	[f]= [d]
Market to Book Value of Common Equity	1.92	2.03	1.70	1.73	1.54	1.47	1.10	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$2,191	$2,191	$2,020	$2,022	$1,753	$1,759	$1,029	[h]
Market Value of Preferred Equity	$2,191	$2,191	$2,020	$2,022	$1,753	$1,759	$1,029	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,605	$2,605	$3,792	$4,498	$3,603	$4,494	$4,751	[j]
Current Liabilities	$5,342	$5,342	$5,239	$5,849	$5,389	$4,274	$4,161	[k]
Current Portion of Long-Term Debt	$881	$881	$295	$704	$401	$565	$51	[l]
Net Working Capital	($1,856)	($1,856)	($1,152)	($647)	($1,385)	$785	$641	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$757	$757	$1,154	$1,349	$1,528	$429	$560	[n]
Adjusted Short-Term Debt	$757	$757	$1,152	$647	$1,385	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$10,407	$10,407	$10,957	$10,133	$9,232	$13,708	$13,010	[p]
Book Value of Long-Term Debt	$12,045	$12,045	$12,404	$11,484	$11,018	$14,273	$13,061	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$12,252	$12,252	$12,319	$11,084	$10,944	$10,548	$12,360	
Carrying Amount	$11,259	$11,259	$10,738	$10,426	$9,231	$8,834	$12,419	
Adjustment to Book Value of Long-Term Debt	$993	$993	$1,581	$658	$1,713	$1,714	($59)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$13,038	$13,038	$13,985	$12,142	$12,731	$15,987	$13,002	[s] = [q] + [r].
Market Value of Debt	$13,038	$13,038	$13,985	$12,142	$12,731	$15,987	$13,002	[t] = [s].
MARKET VALUE OF FIRM								
	$37,855	$39,180	$35,745	$32,748	$29,422	$32,465	$26,189	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	59.77%	61.13%	55.22%	56.75%	50.77%	45.34%	46.42%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	5.79%	5.59%	5.65%	6.17%	5.96%	5.42%	3.93%	[w] = [i] / [u].
Debt - Market Value Ratio	34.44%	33.28%	39.12%	37.08%	43.27%	49.24%	49.65%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel K: El Paso Electric

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$1,075	$1,075	$1,021	$1,016	$894	$830	$813	[a]
Shares Outstanding (in millions) - Common	40	40	40	40	40	40	40	[b]
Price per Share - Common	$46	$47	$36	$37	$33	$34	$32	[c]
Market Value of Common Equity	$1,839	$1,886	$1,432	$1,481	$1,328	$1,356	$1,285	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$1,839	$1,886	$1,432	$1,481	$1,328	$1,356	$1,285	[f]= [d]
Market to Book Value of Common Equity	1.71	1.75	1.40	1.46	1.49	1.63	1.58	[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	$192	$192	$202	$207	$237	$176	$200	[j]
Current Liabilities	$294	$294	$251	$242	$141	$174	$187	[k]
Current Portion of Long-Term Debt	$83	$83	$0	$15	$0	$33	$33	[l]
Net Working Capital	($19)	($19)	($48)	($19)	$96	$35	$46	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$55	$55	$119	$90	$15	$62	$18	[n]
Adjusted Short-Term Debt	$19	$19	$48	$19	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,195	$1,195	$1,134	$985	$1,000	$850	$816	[p]
Book Value of Long-Term Debt	$1,297	$1,297	$1,182	$1,019	$1,000	$883	$850	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,285	$1,285	$1,314	$1,059	$1,182	$1,057	$883	
Carrying Amount	$1,276	$1,276	$1,164	$1,014	$1,022	$883	$854	
Adjustment to Book Value of Long-Term Debt	$9	$9	$150	$45	$160	$174	$28	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,306	$1,306	$1,332	$1,064	$1,160	$1,057	$878	[s] = [q] + [r].
Market Value of Debt	$1,306	$1,306	$1,332	$1,064	$1,160	$1,057	$878	[t] = [s].
MARKET VALUE OF FIRM	$3,145	$3,192	$2,764	$2,544	$2,487	$2,414	$2,163	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.47%	59.09%	51.80%	58.19%	53.38%	56.19%	59.41%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	41.53%	40.91%	48.20%	41.81%	46.62%	43.81%	40.59%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel L: Entergy Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$10,069	$10,069	$9,157	$10,149	$9,408	$9,191	$8,965	[a]
Shares Outstanding (in millions) - Common	179	179	178	180	178	178	176	[b]
Price per Share - Common	$69	$79	$64	$76	$64	$69	$65	[c]
Market Value of Common Equity	$12,406	$14,147	$11,376	$13,736	$11,359	$12,194	$11,495	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$12,406	$14,147	$11,376	$13,736	$11,359	$12,194	$11,495	[f]= [d]
Market to Book Value of Common Equity	1.23	1.40	1.24	1.35	1.21	1.33	1.28	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$233	$233	$211	$305	$281	$281	$311	[h]
Market Value of Preferred Equity	$233	$233	$211	$305	$281	$281	$311	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,340	$4,340	$4,117	$4,265	$3,490	$3,808	$4,154	[j]
Current Liabilities	$3,452	$3,452	$3,454	$4,454	$3,439	$3,924	$4,161	[k]
Current Portion of Long-Term Debt	$753	$753	$281	$1,117	$209	$792	$2,026	[l]
Net Working Capital	$1,641	$1,641	$945	$927	$260	$675	$2,019	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$433	$433	$782	$891	$1,106	$356	$145	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$13,887	$13,887	$13,080	$11,665	$12,308	$11,784	$10,281	[p]
Book Value of Long-Term Debt	$14,640	$14,640	$13,362	$12,782	$12,517	$12,575	$12,307	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$13,579	$13,579	$13,607	$12,440	$12,849	$12,176	$10,989	
Carrying Amount	$13,326	$13,326	$13,399	$12,596	$12,639	$12,236	$11,617	
Adjustment to Book Value of Long-Term Debt	$253	$253	$208	($156)	$210	($60)	($628)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$14,892	$14,892	$13,569	$12,625	$12,728	$12,515	$11,679	[s] = [q] + [r].
Market Value of Debt	$14,892	$14,892	$13,569	$12,625	$12,728	$12,515	$11,679	[t] = [s].
MARKET VALUE OF FIRM	$27,531	$29,272	$25,156	$26,665	$24,367	$24,989	$23,485	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	45.06%	48.33%	45.22%	51.51%	46.62%	48.80%	48.95%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.85%	0.80%	0.84%	1.14%	1.15%	1.12%	1.32%	[w] = [i] / [u].
Debt - Market Value Ratio	54.09%	50.88%	53.94%	47.35%	52.23%	50.08%	49.73%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
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Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel M: IDACORP Inc.

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$2,149	$2,149	$2,050	$1,949	$1,860	$1,770	$1,657	[a]
Shares Outstanding (in millions) - Common	50	50	50	50	50	50	50	[b]
Price per Share - Common	$77	$79	$61	$55	$48	$43	$38	[c]
Market Value of Common Equity	$3,883	$3,961	$3,087	$2,753	$2,403	$2,151	$1,881	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$3,883	$3,961	$3,087	$2,753	$2,403	$2,151	$1,881	[f]= [d]
Market to Book Value of Common Equity	1.81	1.84	1.51	1.41	1.29	1.21	1.14	[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	$460	$460	$494	$475	$567	$366	$309	[j]
Current Liabilities	$205	$205	$205	$240	$335	$268	$254	[k]
Current Portion of Long-Term Debt	$1	$1	$1	$1	$71	$1	$2	[l]
Net Working Capital	$256	$256	$290	$237	$303	$99	$56	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$5	$5	$4	$32	$53	$51	$52	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,746	$1,746	$1,742	$1,614	$1,615	$1,537	$1,487	[p]
Book Value of Long-Term Debt	$1,747	$1,747	$1,743	$1,615	$1,686	$1,538	$1,489	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,813	$1,813	$1,788	$1,600	$1,819	$1,738	$1,623	
Carrying Amount	$1,726	$1,726	$1,616	$1,616	$1,538	$1,492	$1,614	
Adjustment to Book Value of Long-Term Debt	$87	$87	$173	($16)	$282	$246	$9	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,833	$1,833	$1,916	$1,599	$1,968	$1,784	$1,498	[s] = [q] + [r].
Market Value of Debt	$1,833	$1,833	$1,916	$1,599	$1,968	$1,784	$1,498	[t] = [s].
MARKET VALUE OF FIRM	$5,716	$5,795	$5,003	$4,353	$4,370	$3,934	$3,379	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	67.92%	68.36%	61.71%	63.26%	54.97%	54.66%	55.68%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	32.08%	31.64%	38.29%	36.74%	45.03%	45.34%	44.32%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel N: MGE Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$720	$720	$689	$654	$613	$578	$550	[a]
Shares Outstanding (in millions) - Common	35	35	35	35	35	35	35	[b]
Price per Share - Common	$61	$57	$40	$39	$36	$35	$27	[c]
Market Value of Common Equity	$2,114	$1,975	$1,396	$1,340	$1,244	$1,223	$950	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$2,114	$1,975	$1,396	$1,340	$1,244	$1,223	$950	[f]= [d]
Market to Book Value of Common Equity	2.93	2.74	2.03	2.05	2.03	2.11	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	$249	$249	$242	$225	$214	$220	$174	[j]
Current Liabilities	$86	$86	$74	$82	$79	$60	$52	[k]
Current Portion of Long-Term Debt	$4	$4	$4	$4	$4	$3	$3	[l]
Net Working Capital	$167	$167	$172	$147	$139	$162	$124	[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	$384	$384	$392	$396	$400	$359	$362	[p]
Book Value of Long-Term Debt	$388	$388	$396	$400	$405	$362	$364	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$436	$436	$457	$432	$427	$433	$356	
Carrying Amount	$396	$396	$400	$404	$362	$364	$337	
Adjustment to Book Value of Long-Term Debt	$40	$40	$58	$28	$66	$68	$19	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$428	$428	$454	$429	$470	$430	$384	[s] = [q] + [r].
Market Value of Debt	$428	$428	$454	$429	$470	$430	$384	[t] = [s].
MARKET VALUE OF FIRM	$2,542	$2,404	$1,850	$1,769	$1,714	$1,653	$1,333	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	83.15%	82.18%	75.46%	75.77%	72.56%	73.97%	71.23%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	16.85%	17.82%	24.54%	24.23%	27.44%	26.03%	28.77%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel O: OGE Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$3,445	$3,445	$3,353	$3,243	$2,995	$2,769	$2,541	[a]
Shares Outstanding (in millions) - Common	200	200	200	199	198	197	196	[b]
Price per Share - Common	$32	$32	$27	$36	$36	$28	$24	[c]
Market Value of Common Equity	$6,347	$6,386	$5,399	$7,266	$7,104	$5,440	$4,709	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$6,347	$6,386	$5,399	$7,266	$7,104	$5,440	$4,709	[f]= [d]
Market to Book Value of Common Equity	1.84	1.85	1.61	2.24	2.37	1.96	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	$547	$547	$753	$740	$758	$857	$727	[j]
Current Liabilities	$795	$795	$587	$869	$942	$1,196	$934	[k]
Current Portion of Long-Term Debt	$125	$125	$110	$0	$0	$0	$0	[l]
Net Working Capital	($123)	($123)	$276	($129)	($184)	($339)	($208)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$213	$213	$0	$411	$447	$456	$289	[n]
Adjusted Short-Term Debt	$123	$123	$0	$129	$184	$339	$208	[o] = See Sources and Notes.
Long-Term Debt	$2,505	$2,505	$2,646	$2,510	$2,400	$2,848	$2,587	[p]
Book Value of Long-Term Debt	$2,753	$2,753	$2,756	$2,639	$2,584	$3,188	$2,795	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,656	$2,656	$2,550	$2,653	$3,397	$3,276	$2,579	
Carrying Amount	$2,899	$2,899	$2,755	$2,400	$2,849	$2,737	$2,363	
Adjustment to Book Value of Long-Term Debt	($244)	($244)	($206)	$253	$548	$539	$216	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,510	$2,510	$2,550	$2,891	$3,132	$3,726	$3,011	[s] = [q] + [r].
Market Value of Debt	$2,510	$2,510	$2,550	$2,891	$3,132	$3,726	$3,011	[t] = [s].
MARKET VALUE OF FIRM	$8,857	$8,896	$7,949	$10,157	$10,236	$9,166	$7,720	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	71.66%	71.79%	67.92%	71.54%	69.41%	59.35%	61.00%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	28.34%	28.21%	32.08%	28.46%	30.59%	40.65%	39.00%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel P: Otter Tail Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$657	$657	$598	$563	$530	$531	$626	[a]
Shares Outstanding (in millions) - Common	39	39	38	37	36	36	36	[b]
Price per Share - Common	$39	$35	$26	$27	$28	$24	$19	[c]
Market Value of Common Equity	$1,513	$1,380	$972	$1,007	$1,006	$859	$703	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$1,513	$1,380	$972	$1,007	$1,006	$859	$703	[f]= [d]
Market to Book Value of Common Equity	2.30	2.10	1.63	1.79	1.90	1.62	1.12	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$16	$16	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$16	$16	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$204	$204	$274	$298	$310	$299	$372	[j]
Current Liabilities	$246	$246	$237	$200	$220	$176	$216	[k]
Current Portion of Long-Term Debt	$85	$85	$0	$0	$0	$0	$3	[l]
Net Working Capital	$43	$43	$37	$98	$91	$123	$159	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$37	$37	$87	$39	$40	$12	$39	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$461	$461	$498	$499	$437	$422	$433	[p]
Book Value of Long-Term Debt	$546	$546	$499	$499	$437	$422	$437	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$563	$563	$601	$428	$491	$525	$473	
Carrying Amount	$498	$498	$499	$390	$422	$472	$434	
Adjustment to Book Value of Long-Term Debt	$65	$65	$102	$38	$69	$53	$39	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$611	$611	$601	$537	$507	$475	$476	[s] = [q] + [r].
Market Value of Debt	$611	$611	$601	$537	$507	$475	$476	[t] = [s].
MARKET VALUE OF FIRM	$2,124	$1,991	$1,573	$1,544	$1,513	$1,350	$1,195	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	71.22%	69.31%	61.81%	65.24%	66.49%	63.66%	58.84%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	1.15%	1.30%	[w] = [i] / [u].
Debt - Market Value Ratio	28.78%	30.69%	38.19%	34.76%	33.51%	35.19%	39.86%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel Q: PG&E Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$17,354	$17,354	$16,568	$15,779	$14,008	$13,133	$11,959	[a]
Shares Outstanding (in millions) - Common	505	505	490	475	449	429	405	[b]
Price per Share - Common	$59	$62	$51	$46	$41	$43	$42	[c]
Market Value of Common Equity	$29,792	$31,566	$24,840	$21,682	$18,575	$18,401	$17,105	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$29,792	$31,566	$24,840	$21,682	$18,575	$18,401	$17,105	[f]= [d]
Market to Book Value of Common Equity	1.72	1.82	1.50	1.37	1.33	1.40	1.43	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$252	$252	$252	$252	$252	$252	$252	[h]
Market Value of Preferred Equity	$252	$252	$252	$252	$252	$252	$252	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$5,749	$5,749	$6,131	$6,071	$5,522	$5,593	$5,877	[j]
Current Liabilities	$6,270	$6,270	$6,108	$5,726	$7,644	$5,436	$6,818	[k]
Current Portion of Long-Term Debt	$160	$160	$0	$0	$1,288	$110	$468	[l]
Net Working Capital	($361)	($361)	$23	$345	($834)	$267	($473)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,145	$1,145	$881	$426	$953	$397	$1,137	[n]
Adjusted Short-Term Debt	$361	$361	$0	$0	$834	$0	$473	[o] = See Sources and Notes.
Long-Term Debt	$16,528	$16,528	$15,545	$14,555	$11,918	$12,915	$11,626	[p]
Book Value of Long-Term Debt	$17,049	$17,049	$15,545	$14,555	$14,040	$13,025	$12,567	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$16,422	$16,422	$16,203	$13,798	$14,317	$13,356	$12,559	
Carrying Amount	$14,918	$14,918	$14,128	$12,684	$11,994	$11,317	$11,620	
Adjustment to Book Value of Long-Term Debt	$1,504	$1,504	$2,075	$1,114	$2,323	$2,039	$939	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$18,553	$18,553	$17,620	$15,669	$16,363	$15,064	$13,506	[s] = [q] + [r].
Market Value of Debt	$18,553	$18,553	$17,620	$15,669	$16,363	$15,064	$13,506	[t] = [s].
MARKET VALUE OF FIRM	$48,597	$50,371	$42,712	$37,603	$35,190	$33,717	$30,863	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	61.30%	62.67%	58.16%	57.66%	52.78%	54.57%	55.42%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.52%	0.50%	0.59%	0.67%	0.72%	0.75%	0.82%	[w] = [i] / [u].
Debt - Market Value Ratio	38.18%	36.83%	41.25%	41.67%	46.50%	44.68%	43.76%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel R: Pinnacle West Capital

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$4,853	$4,853	$4,654	$4,492	$4,276	$4,056	$3,894	[a]
Shares Outstanding (in millions) - Common	111	111	111	110	110	110	109	[b]
Price per Share - Common	$75	$77	$62	$56	$55	$53	$43	[c]
Market Value of Common Equity	$8,290	$8,563	$6,850	$6,196	$6,003	$5,792	$4,719	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$8,290	$8,563	$6,850	$6,196	$6,003	$5,792	$4,719	[f]= [d]
Market to Book Value of Common Equity	1.71	1.76	1.47	1.38	1.40	1.43	1.21	[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	$977	$977	$1,062	$1,041	$1,350	$1,099	$1,591	[j]
Current Liabilities	$1,110	$1,110	$1,523	$1,449	$1,447	$949	$1,783	[k]
Current Portion of Long-Term Debt	$17	$17	$411	$369	$566	$90	$876	[l]
Net Working Capital	($115)	($115)	($50)	($39)	$470	$240	$684	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$117	$117	$57	$19	$0	$0	$0	[n]
Adjusted Short-Term Debt	$115	$115	$50	$19	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$4,145	$4,145	$3,257	$3,038	$2,820	$3,339	$3,047	[p]
Book Value of Long-Term Debt	$4,278	$4,278	$3,719	$3,426	$3,387	$3,429	$3,923	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$4,106	$4,106	$3,839	$3,579	$3,875	$3,926	$3,913	
Carrying Amount	$3,820	$3,820	$3,415	$3,337	$3,322	$3,496	$3,678	
Adjustment to Book Value of Long-Term Debt	$286	$286	$424	$242	$553	$430	$235	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$4,564	$4,564	$4,143	$3,668	$3,940	$3,859	$4,158	[s] = [q] + [r].
Market Value of Debt	$4,564	$4,564	$4,143	$3,668	$3,940	$3,859	$4,158	[t] = [s].
MARKET VALUE OF FIRM	$12,854	$13,127	$10,993	$9,864	$9,943	$9,651	$8,877	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	64.49%	65.23%	62.31%	62.81%	60.38%	60.01%	53.16%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	35.51%	34.77%	37.69%	37.19%	39.62%	39.99%	46.84%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel S: Portland General

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$2,310	$2,310	$2,232	$1,889	$1,792	$1,717	$1,653	[a]
Shares Outstanding (in millions) - Common	89	89	89	78	78	76	75	[b]
Price per Share - Common	$42	$43	$36	$33	$28	$27	$24	[c]
Market Value of Common Equity	$3,727	$3,833	$3,155	$2,567	$2,212	$2,059	$1,798	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$3,727	$3,833	$3,155	$2,567	$2,212	$2,059	$1,798	[f]= [d]
Market to Book Value of Common Equity	1.61	1.66	1.41	1.36	1.23	1.20	1.09	[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	$476	$476	$605	$542	$565	$784	$740	[j]
Current Liabilities	$448	$448	$465	$482	$380	$648	$511	[k]
Current Portion of Long-Term Debt	$0	$0	$0	$70	$50	$200	$0	[l]
Net Working Capital	$28	$28	$140	$130	$235	$336	$229	[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	$2,325	$2,325	$2,204	$2,251	$1,761	$1,536	$1,798	[p]
Book Value of Long-Term Debt	$2,325	$2,325	$2,204	$2,321	$1,811	$1,736	$1,798	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,455	$2,455	$2,901	$2,074	$1,949	$2,091	$1,968	
Carrying Amount	$2,204	$2,204	$2,501	$1,916	$1,636	$1,735	$1,808	
Adjustment to Book Value of Long-Term Debt	$251	$251	$400	$158	$313	$356	$160	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,576	$2,576	$2,604	$2,479	$2,124	$2,092	$1,958	[s] = [q] + [r].
Market Value of Debt	$2,576	$2,576	$2,604	$2,479	$2,124	$2,092	$1,958	[t] = [s].
MARKET VALUE OF FIRM	$6,303	$6,409	$5,759	$5,046	$4,336	$4,151	$3,756	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	59.13%	59.81%	54.79%	50.87%	51.02%	49.60%	47.87%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	40.87%	40.19%	45.21%	49.13%	48.98%	50.40%	52.13%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel T: PPL Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$9,975	$9,975	$10,222	$13,974	$12,344	$11,214	$10,848	[a]
Shares Outstanding (in millions) - Common	679	679	672	665	630	581	578	[b]
Price per Share - Common	$33	$35	$31	$31	$28	$27	$27	[c]
Market Value of Common Equity	$22,383	$23,739	$20,835	$20,387	$17,754	$15,591	$15,339	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$22,383	$23,739	$20,835	$20,387	$17,754	$15,591	$15,339	[f]= [d]
Market to Book Value of Common Equity	2.24	2.38	2.04	1.46	1.44	1.39	1.41	[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	$2,099	$2,099	$2,990	$5,760	$4,971	$5,227	$5,412	[j]
Current Liabilities	$3,412	$3,412	$4,468	$5,412	$4,948	$4,887	$4,540	[k]
Current Portion of Long-Term Debt	$443	$443	$1,460	$235	$751	$313	$502	[l]
Net Working Capital	($870)	($870)	($18)	$583	$774	$653	$1,374	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$636	$636	$557	$1,099	$499	$526	$428	[n]
Adjusted Short-Term Debt	$636	$636	$18	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$18,069	$18,069	$17,745	$20,522	$19,092	$18,711	$17,675	[p]
Book Value of Long-Term Debt	$19,148	$19,148	$19,223	$20,757	$19,843	$19,024	$18,177	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$33,861	$33,861	$32,170	$35,517	$35,217	$32,271	$26,769	
Carrying Amount	$30,932	$30,932	$28,602	$33,756	$31,744	$29,762	$26,502	
Adjustment to Book Value of Long-Term Debt	$2,929	$2,929	$3,568	$1,761	$3,473	$2,509	$267	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$22,077	$22,077	$22,791	$22,518	$23,316	$21,533	$18,444	[s] = [q] + [r].
Market Value of Debt	$22,077	$22,077	$22,791	$22,518	$23,316	$21,533	$18,444	[t] = [s].
MARKET VALUE OF FIRM	$44,460	$45,816	$43,626	$42,905	$41,070	$37,124	$33,783	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	50.34%	51.81%	47.76%	47.52%	43.23%	42.00%	45.40%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	49.66%	48.19%	52.24%	52.48%	56.77%	58.00%	54.60%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel U: Public Serv. Enterprise

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$13,476	$13,476	$12,933	$12,083	$11,338	$10,806	$10,159	[a]
Shares Outstanding (in millions) - Common	505	505	505	506	506	506	506	[b]
Price per Share - Common	$41	$43	$40	$38	$33	$32	$34	[c]
Market Value of Common Equity	$20,754	$21,487	$20,317	$18,979	$16,702	$16,052	$17,084	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$20,754	$21,487	$20,317	$18,979	$16,702	$16,052	$17,084	[f]= [d]
Market to Book Value of Common Equity	1.54	1.59	1.57	1.57	1.47	1.49	1.68	[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	$3,209	$3,209	$3,204	$3,846	$3,741	$3,978	$4,970	[j]
Current Liabilities	$2,804	$2,804	$3,604	$3,136	$3,235	$3,039	$3,692	[k]
Current Portion of Long-Term Debt	$0	$0	$1,106	$574	$1,010	$975	$1,489	[l]
Net Working Capital	$405	$405	$706	$1,284	$1,516	$1,914	$2,767	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$255	$255	$20	$0	$0	$16	$298	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$10,697	$10,697	$8,132	$8,389	$7,476	$7,334	$7,480	[p]
Book Value of Long-Term Debt	$10,697	$10,697	$9,238	$8,963	$8,486	$8,309	$8,969	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$10,256	$10,256	$10,149	$9,061	$9,324	$9,283	$9,836	
Carrying Amount	$9,568	$9,568	$9,144	$8,643	$7,939	$8,094	$8,940	
Adjustment to Book Value of Long-Term Debt	$688	$688	$1,005	$418	$1,385	$1,189	$896	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$11,385	$11,385	$10,243	$9,381	$9,871	$9,498	$9,865	[s] = [q] + [r].
Market Value of Debt	$11,385	$11,385	$10,243	$9,381	$9,871	$9,498	$9,865	[t] = [s].
MARKET VALUE OF FIRM	$32,139	$32,872	$30,560	$28,360	$26,573	$25,550	$26,949	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	64.58%	65.37%	66.48%	66.92%	62.85%	62.83%	63.39%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	35.42%	34.63%	33.52%	33.08%	37.15%	37.17%	36.61%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel V: SCANA Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$5,663	$5,663	$5,419	$4,948	$4,598	$4,095	$3,838	[a]
Shares Outstanding (in millions) - Common	183	183	143	142	140	132	130	[b]
Price per Share - Common	$71	$73	$53	$50	$47	$48	$40	[c]
Market Value of Common Equity	$12,915	$13,299	$7,565	$7,105	$6,527	$6,379	$5,168	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$12,915	$13,299	$7,565	$7,105	$6,527	$6,379	$5,168	[f]= [d]
Market to Book Value of Common Equity	2.28	2.35	1.40	1.44	1.42	1.56	1.35	[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	$1,453	$1,453	$1,221	$1,359	$1,351	$1,361	$1,421	[j]
Current Liabilities	$1,864	$1,864	$1,294	$1,536	$1,203	$1,411	$1,686	[k]
Current Portion of Long-Term Debt	$117	$117	$16	$52	$19	$176	$285	[l]
Net Working Capital	($294)	($294)	($57)	($125)	$167	$126	$20	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$778	$778	$264	$487	$378	$394	$581	[n]
Adjusted Short-Term Debt	$294	$294	$57	$125	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$6,472	$6,472	$6,018	$5,681	$5,431	$4,976	$4,376	[p]
Book Value of Long-Term Debt	$6,883	$6,883	$6,091	$5,858	$5,450	$5,152	$4,661	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$6,446	$6,446	$6,592	$5,916	$6,115	$5,479	$4,841	
Carrying Amount	$5,998	$5,998	$5,697	$5,449	$5,121	$4,653	$4,488	
Adjustment to Book Value of Long-Term Debt	$448	$448	$895	$467	$994	$826	$352	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$7,331	$7,331	$6,986	$6,325	$6,444	$5,978	$5,013	[s] = [q] + [r].
Market Value of Debt	$7,331	$7,331	$6,986	$6,325	$6,444	$5,978	$5,013	[t] = [s].
MARKET VALUE OF FIRM	$20,246	$20,630	$14,551	$13,430	$12,971	$12,358	$10,181	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	63.79%	64.46%	51.99%	52.90%	50.32%	51.62%	50.76%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	36.21%	35.54%	48.01%	47.10%	49.68%	48.38%	49.24%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel W: Sempra Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$12,346	$12,346	$11,625	$11,333	$10,909	$10,082	$9,630	[a]
Shares Outstanding (in millions) - Common	250	250	248	246	244	242	240	[b]
Price per Share - Common	$100	$107	$93	$105	$86	$65	$51	[c]
Market Value of Common Equity	$24,927	$26,864	$22,956	$25,772	$21,032	$15,801	$12,326	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$24,927	$26,864	$22,956	$25,772	$21,032	$15,801	$12,326	[f]= [d]
Market to Book Value of Common Equity	2.02	2.18	1.97	2.27	1.93	1.57	1.28	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$20	$20	$20	$20	$20	$99	$99	[h]
Market Value of Preferred Equity	$20	$20	$20	$20	$20	$99	$99	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,924	$2,924	$3,606	$4,414	$3,712	$3,078	$2,938	[j]
Current Liabilities	$6,794	$6,794	$5,118	$4,292	$4,530	$4,349	$3,995	[k]
Current Portion of Long-Term Debt	$904	$904	$1,168	$188	$1,441	$709	$137	[l]
Net Working Capital	($2,966)	($2,966)	($344)	$310	$623	($562)	($920)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$2,869	$2,869	$1,097	$1,309	$522	$584	$641	[n]
Adjusted Short-Term Debt	$2,869	$2,869	$344	$0	$0	$562	$641	[o] = See Sources and Notes.
Long-Term Debt	$13,522	$13,522	$12,527	$12,437	$10,478	$11,193	$10,033	[p]
Book Value of Long-Term Debt	$17,295	$17,295	$14,039	$12,625	$11,919	$12,464	$10,811	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$14,633	$14,633	$13,699	$12,676	$13,243	$11,047	$8,883	
Carrying Amount	$13,761	$13,761	$12,347	$12,022	$11,873	$9,826	$8,330	
Adjustment to Book Value of Long-Term Debt	$872	$872	$1,352	$654	$1,370	$1,221	$553	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$18,167	$18,167	$15,391	$13,279	$13,289	$13,685	$11,364	[s] = [q] + [r].
Market Value of Debt	$18,167	$18,167	$15,391	$13,279	$13,289	$13,685	$11,364	[t] = [s].
MARKET VALUE OF FIRM	$43,114	$45,051	$38,367	$39,071	$34,341	$29,585	$23,789	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	57.82%	59.63%	59.83%	65.96%	61.25%	53.41%	51.81%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.05%	0.04%	0.05%	0.05%	0.06%	0.33%	0.42%	[w] = [i] / [u].
Debt - Market Value Ratio	42.14%	40.33%	40.12%	33.99%	38.70%	46.26%	47.77%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel X: Vectren Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$1,731	$1,731	$1,650	$1,581	$1,532	$1,506	$1,452	[a]
Shares Outstanding (in millions) - Common	83	83	83	83	82	82	82	[b]
Price per Share - Common	$49	$50	$40	$40	$33	$28	$27	[c]
Market Value of Common Equity	$4,102	$4,156	$3,324	$3,336	$2,736	$2,334	$2,222	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$4,102	$4,156	$3,324	$3,336	$2,736	$2,334	$2,222	[f]= [d]
Market to Book Value of Common Equity	2.37	2.40	2.02	2.11	1.79	1.55	1.53	[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	$580	$580	$539	$493	$608	$569	$623	[j]
Current Liabilities	$582	$582	$619	$427	$607	$783	$699	[k]
Current Portion of Long-Term Debt	$88	$88	$88	$5	$30	$132	$138	[l]
Net Working Capital	$86	$86	$8	$71	$31	($82)	$62	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$131	$131	$111	$62	$249	$316	$216	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$82	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,714	$1,714	$1,523	$1,572	$1,627	$1,454	$1,581	[p]
Book Value of Long-Term Debt	$1,802	$1,802	$1,611	$1,577	$1,657	$1,667	$1,719	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,910	$1,910	$1,755	$1,895	$1,873	$1,804	$1,841	
Carrying Amount	$1,796	$1,796	$1,577	$1,807	$1,660	$1,622	$1,716	
Adjustment to Book Value of Long-Term Debt	$114	$114	$177	$88	$214	$182	$125	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,916	$1,916	$1,788	$1,665	$1,871	$1,850	$1,844	[s] = [q] + [r].
Market Value of Debt	$1,916	$1,916	$1,788	$1,665	$1,871	$1,850	$1,844	[t] = [s].
MARKET VALUE OF FIRM	$6,017	$6,071	$5,112	$5,001	$4,606	$4,184	$4,066	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	68.17%	68.45%	65.03%	66.70%	59.39%	55.80%	54.64%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	31.83%	31.55%	34.97%	33.30%	40.61%	44.20%	45.36%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel Y: Xcel Energy Inc.

($MM)

	DCF Capital Structure	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	Notes
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	09/30/11	
Book Value, Common Shareholder's Equity	$10,988	$10,988	$10,545	$10,155	$9,547	$8,850	$8,431	[a]
Shares Outstanding (in millions) - Common	508	508	507	505	498	488	485	[b]
Price per Share - Common	$39	$42	$34	$31	$28	$28	$25	[c]
Market Value of Common Equity	$19,913	$21,240	$17,219	$15,664	$13,799	$13,528	$12,021	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$19,913	$21,240	$17,219	$15,664	$13,799	$13,528	$12,021	[f]= [d]
Market to Book Value of Common Equity	1.81	1.93	1.63	1.54	1.45	1.53	1.43	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$105	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$105	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,076	$3,076	$3,344	$3,197	$3,121	$3,371	$2,861	[j]
Current Liabilities	$3,454	$3,454	$3,085	$3,471	$2,839	$3,161	$2,653	[k]
Current Portion of Long-Term Debt	$710	$710	$457	$258	$281	$859	$462	[l]
Net Working Capital	$332	$332	$717	($17)	$562	$1,070	$671	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$366	$366	$64	$697	$302	$304	$50	[n]
Adjusted Short-Term Debt	$0	$0	$0	$17	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$13,403	$13,403	$12,691	$11,502	$10,914	$10,106	$9,450	[p]
Book Value of Long-Term Debt	$14,112	$14,112	$13,148	$11,776	$11,195	$10,965	$9,913	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$14,095	$14,095	$13,360	$11,879	$12,208	$11,735	$10,225	
Carrying Amount	$13,148	$13,148	$11,757	$11,192	$10,402	$9,908	$9,319	
Adjustment to Book Value of Long-Term Debt	$947	$947	$1,603	$687	$1,806	$1,826	$906	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$15,059	$15,059	$14,751	$12,463	$13,001	$12,792	$10,819	[s] = [q] + [r].
Market Value of Debt	$15,059	$15,059	$14,751	$12,463	$13,001	$12,792	$10,819	[t] = [s].
MARKET VALUE OF FIRM	$34,973	$36,299	$31,970	$28,128	$26,800	$26,319	$22,945	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.94%	58.51%	53.86%	55.69%	51.49%	51.40%	52.39%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	0.46%	[w] = [i] / [u].
Debt - Market Value Ratio	43.06%	41.49%	46.14%	44.31%	48.51%	48.60%	47.15%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of December 8, 2016
Capital structure from 3rd Quarter, 2016 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2016 balance sheet information and a 15-trading day average closing price ending on 12/8/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[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 10-K.

Book Value of Equity and Debt

Company	Q3 2016 Book Equity	Q3 2016 Pref. Equity	Q3 2016 Book Debt	Total
ALLETE	55%	0%	45%	100%
Alliant Energy	47%	2%	51%	100%
Amer. Elec. Power	47%	0%	53%	100%
Ameren Corp.	50%	0%	50%	100%
CenterPoint Energy	29%	0%	71%	100%
CMS Energy Corp.	30%	0%	70%	100%
Consol. Edison	50%	0%	50%	100%
Dominion Resources	31%	0%	69%	100%
DTE Energy	49%	0%	51%	100%
Edison Int'l	45%	8%	46%	100%
El Paso Electric	45%	0%	55%	100%
Entergy Corp.	40%	1%	59%	100%
IDACORP Inc.	55%	0%	45%	100%
MGE Energy	65%	0%	35%	100%
OGE Energy	56%	0%	44%	100%
Otter Tail Corp.	55%	0%	45%	100%
PG&E Corp.	50%	1%	49%	100%
Pinnacle West Capital	53%	0%	47%	100%
Portland General	50%	0%	50%	100%
PPL Corp.	34%	0%	66%	100%
Public Serv. Enterprise	56%	0%	44%	100%
SCANA Corp.	45%	0%	55%	100%
Sempra Energy	42%	0%	58%	100%
Vectren Corp.	49%	0%	51%	100%
Xcel Energy Inc.	44%	0%	56%	100%
Average	46.8%	0.5%	52.7%	100.0%

Sources and Notes: Table No. BV-ELEC-3, Panels A to Y.

Table No. BV-ELEC-4

Capital Structure Summary

	DCF Capital Structure			5-Year Average Capital Structure		
Company	Common Equity - Value Ratio [1]	Preferred Equity - Value Ratio [2]	Debt - Value Ratio [3]	Common Equity - Value Ratio [4]	Preferred Equity - Value Ratio [5]	Debt - Value Ratio [6]
ALLETE	65.6%	0.0%	34.4%	60.3%	0.0%	39.7%
Alliant Energy	62.5%	1.5%	36.0%	58.6%	2.1%	39.4%
Amer. Elec. Power	57.8%	0.0%	42.2%	53.6%	0.0%	46.4%
Ameren Corp.	60.3%	0.0%	39.7%	54.9%	0.0%	45.1%
CenterPoint Energy	53.3%	0.0%	46.7%	49.0%	0.0%	51.0%
CMS Energy Corp.	52.2%	0.0%	47.8%	45.6%	0.0%	54.4%
Consol. Edison	58.4%	0.0%	41.6%	57.2%	0.1%	42.7%
Dominion Resources	56.5%	0.0%	43.5%	59.6%	0.3%	40.1%
DTE Energy	62.7%	0.0%	37.3%	57.2%	0.0%	42.8%
Edison Int'l	59.8%	5.8%	34.4%	52.4%	5.6%	42.0%
El Paso Electric	58.5%	0.0%	41.5%	55.8%	0.0%	44.2%
Entergy Corp.	45.1%	0.8%	54.1%	48.2%	1.1%	50.8%
IDACORP Inc.	67.9%	0.0%	32.1%	59.3%	0.0%	40.7%
MGE Energy	83.1%	0.0%	16.9%	74.9%	0.0%	25.1%
OGE Energy	71.7%	0.0%	28.3%	66.9%	0.0%	33.1%
Otter Tail Corp.	71.2%	0.0%	28.8%	64.3%	0.4%	35.4%
PG&E Corp.	61.3%	0.5%	38.2%	56.4%	0.7%	42.9%
Pinnacle West Capital	64.5%	0.0%	35.5%	60.9%	0.0%	39.1%
Portland General	59.1%	0.0%	40.9%	52.0%	0.0%	48.0%
PPL Corp.	50.3%	0.0%	49.7%	45.8%	0.0%	54.2%
Public Serv. Enterprise	64.6%	0.0%	35.4%	64.7%	0.0%	35.3%
SCANA Corp.	63.8%	0.0%	36.2%	52.9%	0.0%	47.1%
Sempra Energy	57.8%	0.0%	42.1%	59.2%	0.1%	40.6%
Vectren Corp.	68.2%	0.0%	31.8%	61.7%	0.0%	38.3%
Xcel Energy Inc.	56.9%	0.0%	43.1%	53.6%	0.0%	46.4%
Average	61.3%	0.3%	38.3%	57.0%	0.4%	42.6%
Subsample Average	60.5%	0.2%	39.3%	56.0%	0.3%	43.7%

Sources and Notes:
[1], [4]: Supporting Schedule #1 to Table No. BV-ELEC-4.
[2], [5]: Supporting Schedule #2 to Table No. BV-ELEC-4.
[3], [6]: Supporting Schedule #3 to Table No. BV-ELEC-4.
Values in this table may not add up exactly to 100% because of rounding.

Table No. BV-ELEC-5

Estimated Growth Rates

Company	ThomsonOne IBES Estimate		Value Line			
	Long-Term Growth Rate	Number of Estimates	EPS Year 2016 Estimate	EPS Year 2019-2021 Estimate	Annualized Growth Rate	Combined Growth Rate
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	5.00%	1	$3.15	$3.75	4.5%	4.7%
Alliant Energy	6.00%	1	$1.90	$2.45	6.6%	6.3%
Amer. Elec. Power	1.89%	1	$3.85	$4.25	2.5%	2.2%
Ameren Corp.	5.65%	2	$2.60	$3.25	5.7%	5.7%
CenterPoint Energy	6.07%	4	$1.00	$1.40	8.8%	6.6%
CMS Energy Corp.	7.27%	2	$1.95	$2.50	6.4%	7.0%
Consol. Edison	2.12%	3	$3.95	$4.50	3.3%	2.4%
Dominion Resources	5.95%	5	$3.65	$5.50	10.8%	6.8%
DTE Energy	5.63%	3	$4.80	$6.25	6.8%	5.9%
Edison Int'l	2.07%	2	$3.95	$5.00	6.1%	3.4%
El Paso Electric	7.00%	1	$2.25	$2.75	5.1%	6.1%
Entergy Corp.	-8.34%	2	$7.00	$6.25	-2.8%	-6.5%
IDACORP Inc.	4.10%	2	$3.90	$4.50	3.6%	3.9%
MGE Energy	4.00%	1	$2.30	$3.25	9.0%	6.5%
OGE Energy	4.00%	1	$1.75	$2.25	6.5%	5.2%
Otter Tail Corp.	6.00%	1	$1.60	$2.10	7.0%	6.5%
PG&E Corp.	5.83%	6	$2.90	$4.50	11.6%	6.7%
Pinnacle West Capital	4.63%	3	$3.95	$4.75	4.7%	4.7%
Portland General	6.67%	3	$2.15	$2.75	6.3%	6.6%
PPL Corp.	2.44%	3	$2.65	$2.50	-1.4%	1.5%
Public Serv. Enterprise	1.23%	2	$2.75	$3.25	4.3%	2.2%
SCANA Corp.	6.03%	4	$4.00	$4.75	4.4%	5.7%
Sempra Energy	6.50%	3	$3.80	$7.50	18.5%	9.5%
Vectren Corp.	4.57%	3	$2.45	$3.35	8.1%	5.5%
Xcel Energy Inc.	5.65%	3	$2.20	$2.75	5.7%	5.7%

Sources and Notes:

[1] - [2]: Updated from ThomsonOne as of Dec 08, 2016.

[3] - [4]: From Valueline Investment Analyzer as of Sep 02, 2016.

[5]: ([4]/[3])^(1/4) - 1, where 4 is the number of years between 2020, the middle year of Value Line's 3-5 year forecast, and our study year 2016.

[6]: Weighted average growth rate.

Table No. BV-ELEC-6

DCF Cost of Equity of the U.S. Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	Stock Price [1]	Most Recent Dividend [2]	Quarterly Dividend Yield (t+1) [3]	Combined Long-Term Growth Rate [4]	Quarterly Growth Rate [5]	DCF Cost of Equity [6]
ALLETE	$62.37	$0.52	0.84%	4.7%	1.2%	8.3%
Alliant Energy	$36.16	$0.29	0.82%	6.3%	1.5%	9.8%
Amer. Elec. Power	$59.43	$0.59	1.00%	2.2%	0.5%	6.3%
Ameren Corp.	$49.16	$0.44	0.91%	5.7%	1.4%	9.5%
CenterPoint Energy	$23.81	$0.26	1.10%	6.6%	1.6%	11.3%
CMS Energy Corp.	$40.32	$0.31	0.78%	7.0%	1.7%	10.3%
Consol. Edison	$70.29	$0.67	0.96%	2.4%	0.6%	6.4%
Dominion Resources	$72.89	$0.70	0.98%	6.8%	1.6%	10.9%
DTE Energy	$94.17	$0.77	0.83%	5.9%	1.5%	9.4%
Edison Int'l	$69.45	$0.48	0.70%	3.4%	0.8%	6.3%
El Paso Electric	$45.55	$0.31	0.69%	6.1%	1.5%	9.0%
Entergy Corp.	$69.26	$0.87	1.24%	-6.5%	-1.7%	-1.7%
IDACORP Inc.	$77.03	$0.55	0.72%	3.9%	1.0%	6.9%
MGE Energy	$60.98	$0.31	0.51%	6.5%	1.6%	8.7%
OGE Energy	$31.78	$0.30	0.96%	5.2%	1.3%	9.3%
Otter Tail Corp.	$38.57	$0.31	0.82%	6.5%	1.6%	10.0%
PG&E Corp.	$58.97	$0.49	0.84%	6.7%	1.6%	10.2%
Pinnacle West Capital	$74.53	$0.66	0.89%	4.7%	1.1%	8.4%
Portland General	$41.91	$0.32	0.78%	6.6%	1.6%	9.9%
PPL Corp.	$32.95	$0.38	1.16%	1.5%	0.4%	6.2%
Public Serv. Enterprise	$41.10	$0.41	1.00%	2.2%	0.6%	6.4%
SCANA Corp.	$70.57	$0.58	0.83%	5.7%	1.4%	9.2%
Sempra Energy	$99.71	$0.76	0.77%	9.5%	2.3%	12.9%
Vectren Corp.	$49.48	$0.42	0.86%	5.5%	1.3%	9.1%
Xcel Energy Inc.	$39.20	$0.34	0.88%	5.7%	1.4%	9.4%

Sources and Notes:
[1]: Supporting Schedule #1 to Table No. BV-ELEC-6.
[2]: Supporting Schedule #2 to Table No. BV-ELEC-6.
[3]: ([2] / [1]) x (1 + [5]).
[4]: Table No. BV-ELEC-5, [6].
[5]: {(1 + [4]) ^ (1/4)} - 1.
[6]: {([3] + [5] + 1) ^ 4} - 1.

Table No. BV-ELEC-6

DCF Cost of Equity of the U.S. Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Economic Indicators, October 2016 U.S. GDP Growth Forecast as the Perpetual Rate)

Company	Stock Price [1]	Most Recent Dividend [2]	Combined Long-Term Growth Rate [3]	Growth Rate: Year 6 [4]	Growth Rate: Year 7 [5]	Growth Rate: Year 8 [6]	Growth Rate: Year 9 [7]	Growth Rate: Year 10 [8]	GDP Long-Term Growth Rate [9]	DCF Cost of Equity [10]
ALLETE	$62.37	$0.52	4.73%	4.62%	4.52%	4.41%	4.31%	4.20%	4.10%	7.8%
Alliant Energy	$36.16	$0.29	6.28%	5.92%	5.55%	5.19%	4.83%	4.46%	4.10%	8.0%
Amer. Elec. Power	$59.43	$0.59	2.20%	2.51%	2.83%	3.15%	3.47%	3.78%	4.10%	7.8%
Ameren Corp.	$49.16	$0.44	5.68%	5.42%	5.15%	4.89%	4.63%	4.36%	4.10%	8.3%
CenterPoint Energy	$23.81	$0.26	6.61%	6.19%	5.77%	5.36%	4.94%	4.52%	4.10%	9.4%
CMS Energy Corp.	$40.32	$0.31	6.98%	6.50%	6.02%	5.54%	5.06%	4.58%	4.10%	8.0%
Consol. Edison	$70.29	$0.67	2.42%	2.70%	2.98%	3.26%	3.54%	3.82%	4.10%	7.7%
Dominion Resources	$72.89	$0.70	6.76%	6.31%	5.87%	5.43%	4.99%	4.54%	4.10%	8.9%
DTE Energy	$94.17	$0.77	5.93%	5.62%	5.32%	5.01%	4.71%	4.40%	4.10%	8.0%
Edison Int'l	$69.45	$0.48	3.40%	3.52%	3.64%	3.75%	3.87%	3.98%	4.10%	6.9%
El Paso Electric	$45.55	$0.31	6.07%	5.74%	5.41%	5.09%	4.76%	4.43%	4.10%	7.4%
Entergy Corp.	$69.26	$0.87	-6.49%	-4.73%	-2.96%	-1.20%	0.57%	2.33%	4.10%	6.7%
IDACORP Inc.	$77.03	$0.55	3.95%	3.97%	4.00%	4.02%	4.05%	4.07%	4.10%	7.1%
MGE Energy	$60.98	$0.31	6.51%	6.11%	5.71%	5.31%	4.90%	4.50%	4.10%	6.6%
OGE Energy	$31.78	$0.30	5.24%	5.05%	4.86%	4.67%	4.48%	4.29%	4.10%	8.4%
Otter Tail Corp.	$38.57	$0.31	6.52%	6.11%	5.71%	5.31%	4.91%	4.50%	4.10%	8.1%
PG&E Corp.	$58.97	$0.49	6.66%	6.23%	5.80%	5.38%	4.95%	4.53%	4.10%	8.2%
Pinnacle West Capital	$74.53	$0.66	4.65%	4.56%	4.47%	4.38%	4.28%	4.19%	4.10%	7.9%
Portland General	$41.91	$0.32	6.59%	6.17%	5.76%	5.34%	4.93%	4.51%	4.10%	7.9%
PPL Corp.	$32.95	$0.38	1.47%	1.91%	2.35%	2.78%	3.22%	3.66%	4.10%	8.2%
Public Serv. Enterprise	$41.10	$0.41	2.24%	2.55%	2.86%	3.17%	3.48%	3.79%	4.10%	7.8%
SCANA Corp.	$70.57	$0.58	5.70%	5.43%	5.17%	4.90%	4.63%	4.37%	4.10%	7.9%
Sempra Energy	$99.71	$0.76	9.51%	8.61%	7.70%	6.80%	5.90%	5.00%	4.10%	8.6%
Vectren Corp.	$49.48	$0.42	5.46%	5.23%	5.01%	4.78%	4.55%	4.33%	4.10%	8.0%
Xcel Energy Inc.	$39.20	$0.34	5.67%	5.41%	5.15%	4.89%	4.62%	4.36%	4.10%	8.1%

Sources and Notes:
[1]: Supporting Schedule #1 to Table No. BV-ELEC-6.
[2]: Supporting Schedule #2 to Table No. BV-ELEC-6.
[3]: Table No. BV-ELEC-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]: Blue Chip Economic Indicators, October 2016 U.S. This number is assumed to be the perpetual growth rate.
[10]: Supporting Schedule #3 to Table No. BV-ELEC-6.

Table No. BV-ELEC-7

Overall After-Tax DCF Cost of Capital of the U.S. Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	3rd Quarter, 2016 Bond Rating [1]	3rd Quarter, 2016 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	POR Representative Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
ALLETE	BBB	-	8.3%	65.6%	-	0.0%	4.6%	34.4%	39.9%	6.37%
Alliant Energy	A	A	9.8%	62.5%	4.2%	1.5%	4.2%	36.0%	39.9%	7.09%
Amer. Elec. Power	BBB	-	6.3%	57.8%	-	0.0%	4.6%	42.2%	39.9%	4.81%
Ameren Corp.	BBB	-	9.5%	60.3%	-	0.0%	4.6%	39.7%	39.9%	6.83%
CenterPoint Energy	A	-	11.3%	53.3%	-	0.0%	4.2%	46.7%	39.9%	7.21%
CMS Energy Corp.	BBB	-	10.3%	52.2%	-	0.0%	4.6%	47.8%	39.9%	6.70%
Consol. Edison	A	-	6.4%	58.4%	-	0.0%	4.2%	41.6%	39.9%	4.78%
Dominion Resources	BBB	-	10.9%	56.5%	-	0.0%	4.6%	43.5%	39.9%	7.37%
DTE Energy	BBB	-	9.4%	62.7%	-	0.0%	4.6%	37.3%	39.9%	6.94%
Edison Int'l	BBB	BBB	6.3%	59.8%	4.6%	5.8%	4.6%	34.4%	39.9%	5.0%
El Paso Electric	BBB	-	9.0%	58.5%	-	0.0%	4.6%	41.5%	39.9%	6.40%
Entergy Corp.	BBB	BBB	-1.7%	45.1%	4.6%	0.8%	4.6%	54.1%	39.9%	~~0.8%~~
IDACORP Inc.	BBB	-	6.9%	67.9%	-	0.0%	4.6%	32.1%	39.9%	5.60%
MGE Energy	AA	-	8.7%	83.1%	-	0.0%	4.1%	16.9%	39.9%	7.63%
OGE Energy	A	-	9.3%	71.7%	-	0.0%	4.2%	28.3%	39.9%	7.39%
Otter Tail Corp.	BBB	-	10.0%	71.2%	-	0.0%	4.6%	28.8%	39.9%	7.92%
PG&E Corp.	BBB	BBB	10.2%	61.3%	4.6%	0.5%	4.6%	38.2%	39.9%	7.36%
Pinnacle West Capital	A	-	8.4%	64.5%	-	0.0%	4.2%	35.5%	39.9%	6.31%
Portland General	BBB	-	9.9%	59.1%	-	0.0%	4.6%	40.9%	39.9%	6.97%
PPL Corp.	A	-	6.2%	50.3%	-	0.0%	4.2%	49.7%	39.9%	4.40%
Public Serv. Enterprise	BBB	-	6.4%	64.6%	-	0.0%	4.6%	35.4%	39.9%	5.10%
SCANA Corp.	BBB	-	9.2%	63.8%	-	0.0%	4.6%	36.2%	39.9%	6.86%
Sempra Energy	BBB	BBB	12.9%	57.8%	4.6%	0.0%	4.6%	42.1%	39.9%	8.60%
Vectren Corp.	A	-	9.1%	68.2%	-	0.0%	4.2%	31.8%	39.9%	7.00%
Xcel Energy Inc.	A	-	9.4%	56.9%	-	0.0%	4.2%	43.1%	39.9%	6.44%
Simple Full Sample Average			8.9%	62.0%	4.5%	0.3%	4.4%	37.7%	39.9%	6.54%
Simple Subsample Average			8.8%	61.5%	4.4%	0.1%	4.4%	38.4%	39.9%	6.43%
	$E$14:$E$38	$F$14:$F$38	$G$14:$G$38	$H$14:$H$38	$I$14:$I$38	$J$14:$J$38	K$14:$K$3	$L$14:$L$38	$M$14:$M$38	$N$14:$N$38

Sources and Notes:
[1]: S&P Credit Ratings from Research Insight.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. BV-ELEC-6; Panel A, [6].
[4]: Table No. BV-ELEC-4, [1].
[5]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[6]: Table No. BV-ELEC-4, [2].
[7]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel B.
[8]: Table No. BV-ELEC-4, [3].
[9]: AMLP Effective Corporate Tax Rate.
[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 100 basis points.

Table No. BV-ELEC-7

Overall After-Tax DCF Cost of Capital of the U.S. Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Economic Indicators, October 2016 U.S. GDP Growth Forecast as the Perpetual Rate)

Company	3rd Quarter, 2016 Bond Rating [1]	3rd Quarter, 2016 Preferred Equity Rating	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	POR Representative Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
ALLETE	BBB	-	7.8%	65.6%	-	0.0%	4.6%	34.4%	39.9%	6.04%
Alliant Energy	A	A	8.0%	62.5%	4.2%	1.5%	4.2%	36.0%	39.9%	6.00%
Amer. Elec. Power	BBB	-	7.8%	57.8%	-	0.0%	4.6%	42.2%	39.9%	5.68%
Ameren Corp.	BBB	-	8.3%	60.3%	-	0.0%	4.6%	39.7%	39.9%	6.08%
CenterPoint Energy	A	-	9.4%	53.3%	-	0.0%	4.2%	46.7%	39.9%	6.2%
CMS Energy Corp.	BBB	-	8.0%	52.2%	-	0.0%	4.6%	47.8%	39.9%	5.49%
Consol. Edison	A	-	7.7%	58.4%	-	0.0%	4.2%	41.6%	39.9%	5.56%
Dominion Resources	BBB	-	8.9%	56.5%	-	0.0%	4.6%	43.5%	39.9%	6.2%
DTE Energy	BBB	-	8.0%	62.7%	-	0.0%	4.6%	37.3%	39.9%	6.03%
Edison Int'l	BBB	BBB	6.9%	59.8%	4.6%	5.8%	4.6%	34.4%	39.9%	5.32%
El Paso Electric	BBB	-	7.4%	58.5%	-	0.0%	4.6%	41.5%	39.9%	5.44%
Entergy Corp.	BBB	BBB	6.7%	45.1%	4.6%	0.8%	4.6%	54.1%	39.9%	4.54%
IDACORP Inc.	BBB	-	7.1%	67.9%	-	0.0%	4.6%	32.1%	39.9%	5.69%
MGE Energy	AA	-	6.6%	83.1%	-	0.0%	4.1%	16.9%	39.9%	5.88%
OGE Energy	A	-	8.4%	71.7%	-	0.0%	4.2%	28.3%	39.9%	6.8%
Otter Tail Corp.	BBB	-	8.1%	71.2%	-	0.0%	4.6%	28.8%	39.9%	6.5%
PG&E Corp.	BBB	BBB	8.2%	61.3%	4.6%	0.5%	4.6%	38.2%	39.9%	6.11%
Pinnacle West Capital	A	-	7.9%	64.5%	-	0.0%	4.2%	35.5%	39.9%	6.02%
Portland General	BBB	-	7.9%	59.1%	-	0.0%	4.6%	40.9%	39.9%	5.78%
PPL Corp.	A	-	8.2%	50.3%	-	0.0%	4.2%	49.7%	39.9%	5.41%
Public Serv. Enterprise	BBB	-	7.8%	64.6%	-	0.0%	4.6%	35.4%	39.9%	6.04%
SCANA Corp.	BBB	-	7.9%	63.8%	-	0.0%	4.6%	36.2%	39.9%	6.0%
Sempra Energy	BBB	BBB	8.6%	57.8%	4.6%	0.0%	4.6%	42.1%	39.9%	6.1%
Vectren Corp.	A	-	8.0%	68.2%	-	0.0%	4.2%	31.8%	39.9%	6.3%
Xcel Energy Inc.	A	-	8.1%	56.9%	-	0.0%	4.2%	43.1%	39.9%	5.7%
Multi Full Sample Average			7.9%	61.3%	4.5%	0.3%	4.5%	38.3%	39.9%	5.9%
Multi Subsample Average			7.9%	60.5%	4.5%	0.17%	4.4%	39.3%	39.9%	5.8%
	$E$69:$E$93	$F$69:$F$93	$G$69:$G$93	$H$69:$H$93	$I$69:$I$93	$J$69:$J$93	K$69:$K$9	$L$69:$L$93	$M$69:$M$93	$N$69:$N$93

Sources and Notes:
[1]: S&P Credit Ratings from Research Insight.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. BV-ELEC-6; Panel B, [10].
[4]: Table No. BV-ELEC-4, [1].
[5]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[6]: Table No. BV-ELEC-4, [2].
[7]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel B.
[8]: Table No. BV-ELEC-4, [3].
[9]: AMLP Effective Corporate Tax Rate.
[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 100 basis points.

Table No. BV-ELEC-8

DCF Cost of Equity at Representative Deemed Capital Structure

	Overall After -Tax Cost of Capital [1]	POR Representative Base Deemed % Debt [2]	Representative Cost of BBB Rated Utility Debt [3]	POR Representative Income Tax Rate [4]	POR Representative Base Deemed % Equity [5]	Estimated Return on Equity [6]
Full Sample						
Simple DCF Quarterly	6.5%	50.0%	4.6%	39.9%	50.0%	10.3%
Multi-Stage DCF - Using Long-Term GDP Growth Forecast as the Perpetual Rate	5.9%	50.0%	4.6%	39.9%	50.0%	9.0%
Subsample						
Simple DCF Quarterly	6.4%	50.0%	4.6%	39.9%	50.0%	10.1%
Multi-Stage DCF - Using Long-Term GDP Growth Forecast as the Perpetual Rate	5.8%	50.0%	4.6%	39.9%	50.0%	8.9%

Sources and Notes:
[1]: Table No. BV-ELEC-7; Panels A-B, [10].
[2]: AMLP Assumed Capital Structure.
[3]: Based on an BBB rating. Yield from Bloomberg as of December 8, 2016.
[4]: AMLP Effective Corporate Tax Rate.
[5]: AMLP Assumed Capital Structure.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

U.S. Electric Sample

Company	DCF Subsample	Annual Revenues (USD million)	Regulated Assets	Market Cap. 2016 Q3 (USD million)	Betas	S&P Credit Rating (2016)	Long Term Growth Est.
	[2]	[3]	[4]	[5]	[6]	[7]	[8]
ALLETE		$1,379	M	$2,997	0.75	BBB+	4.7%
Alliant Energy	*	$3,263	R	$8,841	0.70	A-	6.3%
Amer. Elec. Power	*	$16,205	R	$32,042	0.65	BBB+	2.2%
Ameren Corp.	*	$6,028	R	$12,115	0.65	BBB+	5.7%
CenterPoint Energy		$7,238	M	$10,097	0.85	A-	6.6%
CMS Energy Corp.	*	$6,268	R	$11,917	0.65	BBB+	7.0%
Consol. Edison	*	$12,074	R	$23,296	0.55	A-	2.4%
Dominion Resources		$11,207	M	$47,252	0.65	BBB+	6.8%
DTE Energy	*	$10,243	R	$16,898	0.65	BBB+	5.9%
Edison Int'l		$11,325	R	$23,951	0.65	BBB+	3.4%
El Paso Electric	*	$876	R	$1,886	0.70	BBB	6.1%
Entergy Corp.	*	$10,706	R	$14,147	0.65	BBB+	-6.5%
IDACORP Inc.	*	$1,254	R	$3,961	0.75	BBB	3.9%
MGE Energy		$537	M	$1,975	0.70	AA-	6.5%
OGE Energy	*	$2,176	R	$6,386	0.90	A-	5.2%
Otter Tail Corp.	*	$796	R	$1,380	0.85	BBB	6.5%
PG&E Corp.	*	$17,120	R	$31,566	0.65	BBB+	6.7%
Pinnacle West Capital	*	$3,494	R	$8,563	0.70	A-	4.7%
Portland General	*	$1,898	R	$3,833	0.70	BBB	6.6%
PPL Corp.	*	$7,465	R	$23,739	0.70	A-	1.5%
Public Serv. Enterprise		$9,249	M	$21,487	0.70	BBB+	2.2%
SCANA Corp.		$4,126	M	$13,299	0.70	BBB+	5.7%
Sempra Energy		$10,014	M	$26,864	0.80	BBB+	9.5%
Vectren Corp.	*	$2,354	R	$4,156	0.75	A-	5.5%
Xcel Energy Inc.	*	$10,958	R	$21,240	0.60	A-	5.7%
Full Sample Average		**$6,730**		**$14,956**	**0.70**		**4.8%**
Subsample Average		**$6,657**		**$13,292**	**0.69**		**4.4%**

Sources and Notes:
[1]-[2]: Denotes companies used in the CAPM and DCF subsamples.
[3]: Bloomberg as of December 8, 2016. Most recent four quarters.
[4]: See Table No. BV-ELEC-2. Key:
R - Regulated (More than 80% of assets regulated).
M - Mostly Regulated (50%-80% of assets regulated).
[5]: See Table No. BV-ELEC-3 Panels A through Y.
[6]: See Supporting Schedule # 1 to Table No. BV-ELEC-10.
[7]: S&P Credit Ratings from Research Insight as of 2016 Q3. Research Insight does not report S&P credit ratings for MGE Energy. I use the S&P ratings of MGEE's subsidiary, Madison Gas and Electric Company.
[8]: See Table No. BV-ELEC-5.

DCF Return on Equity Summary

	With Leverage Adjustments
Full Sample	
Simple	10.3%
Multi-Stage	9.0%
Subsample	
Simple	10.1%
Multi-Stage	8.9%

DCF Estimates for alternate GDP growth rates:

Simple	10.3%
Multi-stage using Blue Chip GDP growth:	9.0%
Multi-stage using average of Blue Chip and OMB GDP growth:	9.1%

EXHIBIT PGE 1102

RISK PREMIUM ANALYSIS

Risk Premium Model Cost of Equity Inputs

Forecasted 10-Year Government Bond Rate
2.8%
Source: October 2016 Blue Chip consensus forecast for 2018

Historical Average 10Y to 20Y Maturity Premium
0.54%
Source: Bloomberg

Utility Yield Spread Adjustment
0.55%
Source: PGE Exhibit 1106

Case Type
Vertically Integrated

Risk Premiums Determined by Relationship Between Authorized ROEs[1] and Long-term Treasury Bond Rates During the Period 1990-2016

Formula: Risk Premium = A_0 + (A_1 x Treasury bond Rate)

R Squared	0.8282
Estimate of intercept (A_0)	8.809%
Estimate of slope (A_1)	-0.5844

Equity Cost Estimate for Vertically Integrated Electric		Predicted Risk Premium		Expected Treasury Bond Rate[2]	
10.4%	=	6.54%	+	3.89%	[3]
9.9%	=	6.54%	+	3.34%	[4]

<u>Sources and Notes:</u>
[1]: Authorized ROE Data sourced from SNL Financial.
[2]: Blue Chip consensus forecast 2018 10-yr T-bill Yield plus maturity premium
[3]: Estimate with expected treasury bond rate normalized with 0.55% utility yield spread adjustment
[4]: Estimate without treasury bond rate normalization.
See regression results for derivation of regression coefficients A_0 and A_1.

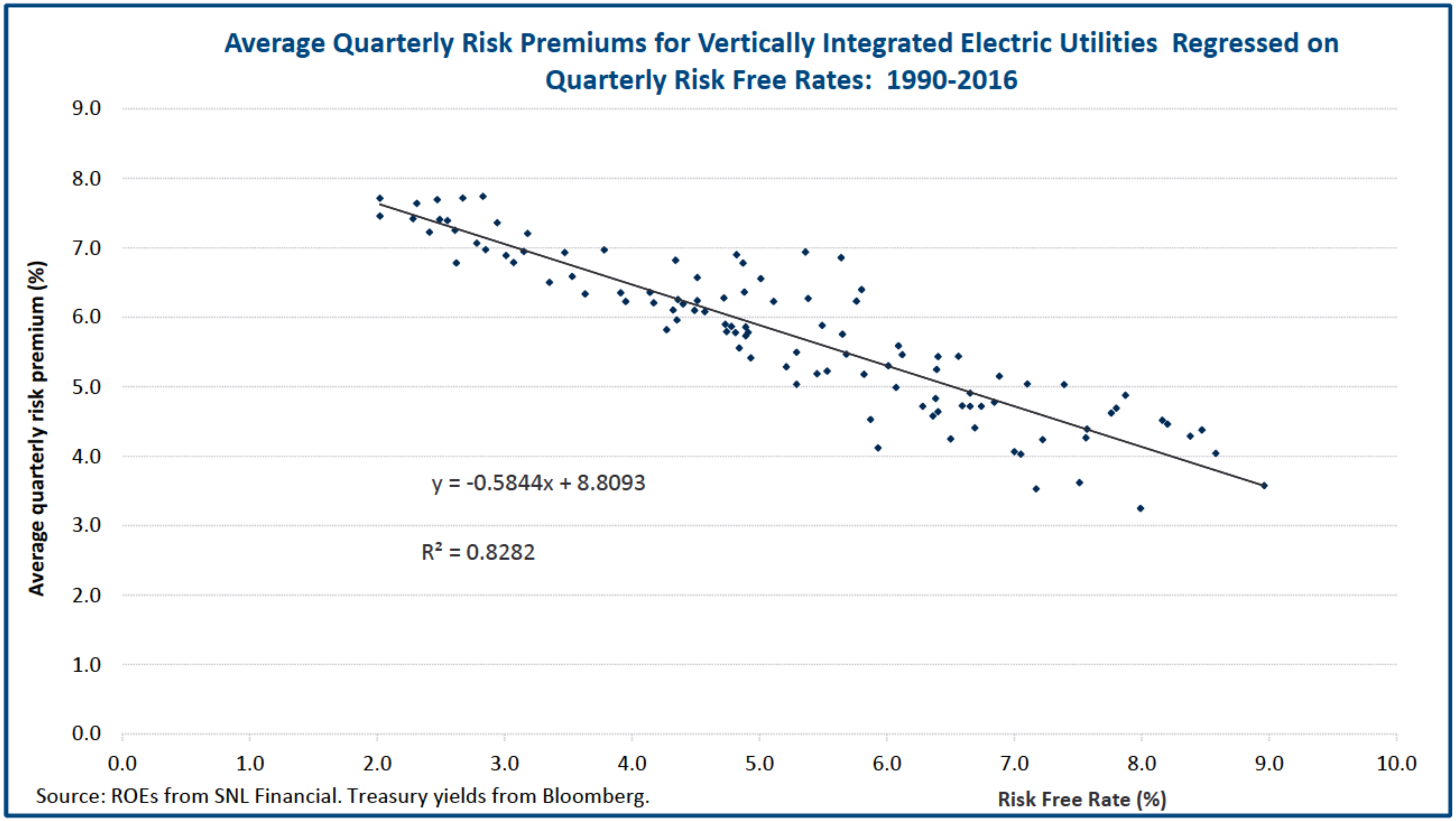
Average Quarterly Risk Premiums for Vertically Integrated Electric Utilities Regressed on Quarterly Risk Free Rates: 1990-2016
Average quarterly risk premium (%)
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
y = -0.5844x + 8.8093
R² = 0.8282
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
10.0
Source: ROEs from SNL Financial. Treasury yields from Bloomberg.
Risk Free Rate (%)

EXHIBIT PGE 1103: The CAPM-Based Estimates

Q. Can you explain the CAPM?

A. Modern models of capital market equilibrium express the cost of equity as the sum of a risk-free rate and a market risk premium. The CAPM is the longest-standing and most widely used of these theories. To implement the model requires specification of (i) the current values of the benchmarks that determine the Security Market Line (see Figure 1 of my Direct Testimony); (i) the relative risk of a security or investment; and (iii) how the benchmarks combine to produce the Security Market Line. Given these specifications, the company's cost of capital can be calculated based on its relative risk. Specifically, the CAPM states that the cost of capital for an investment, S (e.g., a particular common stock), is given by the following equation:

$$r_S = r_f + \beta_S \times MRP \tag{1}$$

where r_s is the cost of capital for investment *S*; r_f is the risk-free rate; β_S is the beta risk measure for the investment *S*; and *MRP* is the market risk premium. The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities. It says that the Security Market Line starts at the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 1, equals the risk-free interest rate). 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 risk premium on a value-weighted portfolio of all investments, which by definition has average risk.

1. The Risk-free Interest Rate

Q. What interest rates do your procedures require?

A. Practitioners and regulators commonly use the long-term version of the CAPM and therefore a long-term risk-free rate. I also rely upon the long-term version of the CAPM. Accordingly, the implementation of my procedures requires use of long-term U.S. Treasury bond interest rates. To determine today's cost of capital, I obtain this information from the 15-day average yield on 20-year Treasury bonds as reported by Bloomberg for the period ending on the date of my analysis. However, rates determined under the current proceeding are expected to be in place for 2017 onward. Therefore, the best estimate of the risk-free rate is a forecast of the rate during the period where rates will be in effect. I therefore use the forecasted rate for 2018 as a reasonable representative benchmark rate.

I add the spread between the 20-year and the 10-year government bond yield to the average Blue Chip Economic Indicators forecast of the 10-year government bond yield for 2018, I obtain a basic risk-free rate estimate of 3.34%.[1]

2. The Market Risk Premium

Q. Why is a risk premium necessary?

A. Experience (e.g., the recent credit crisis in stock markets worldwide and the U.S. market's October Crash of 1987) demonstrates that shareholders, even well diversified shareholders, are exposed to enormous risks. By investing in stocks instead of risk-free government Treasury bills, investors subject themselves not only to the risk of earning a return well

[1] Blue Chip Economic Indicators, October 2016 and Bloomberg data.

below that which they expected in any year but also to the risk that they might lose much of their initial capital. This is fundamentally why investors demand a risk premium.

Q. What is the evidence on the magnitude of the MRP?

A. Historically, it was generally accepted that the appropriate method to estimate the MRP was to consider the historical average realized return on the market minus the return on a risk-free asset over as long a series of time as possible; however, this procedure came under attack during the period of time generally referred to as the "tech bubble" when the stock markets in the U.S. reached very high valuation levels relative to traditional metrics of value. The period of the tech bubble also resulted in the average realized return on the market increasing to a very high level.

Attempts to explain the high stock market valuation levels centered on the hypothesis that the MRP must be dramatically lower than previously believed, but this hypothesis conflicted with the fact that realized returns over the period were very high. The result was an academic debate on the level of the forward-looking MRP and how best to estimate it. However, evidence following the financial crisis of 2007 onward has indicated that the risk premium in recent years has been higher than its historical average. As noted earlier, Duarte and Rosa of the Federal Reserve of New York summarized many of the models developed during the "tech bubble" and also estimated the MRP from the models each year from 1960 through 2013.[2] The authors then reported the average as well as the 25 and 75-percentile of results and found substantially higher MRP since the financial crisis. Figure 3 from Duarte & Rosa 2015 is replicated in my direct testimony as Figure 5 and shows the average

[2] Fernando Duarte and Carlo Rosa, "The Equity Risk Premium: A Consensus of Models," Federal Reserve Bank of New York, December 2015 (Duarte & Rosa 2015).

estimated MRP (over 30-day T-bills) for 20 models.[3] For example, the authors estimate that the MRP reached an all-time high of 14.5% over 90-day T-bills in July 2013 for an approximate long-term MRP of 10.2% over 20-year government bonds. Bloomberg's forecasted MRP at 7.6% over 10-year Treasury bonds is a bit higher than the historical average MRP of about 6.9% (over long-term government bonds).[4] For the purpose of this proceeding I rely on two scenarios. The first scenario looks at the spread between A rated utility bond yields and government bond yields before the financial crisis and as of today. The increase is about 58 basis points (see Exhibit PGE 1106) and Scenario I add 55 basis points of this to the forecasted risk-free rate to obtain a normalized risk-free rate of 3.89%. Scenario II considers that the widening in yield spread and the forecasted MRP is evidence that the current MRP is higher than its historical average. Therefore, Scenario II adds 1% to the MRP but maintains the forecasted risk-free rate. Thus, the two scenarios are:

Parameters Used in CAPM-based Models

	Scenario 1	Scenario 2
Risk-Free Interest Rate	3.9%	3.3%
Market Equity Risk Premium	6.9%	7.9%

3. Beta

Q. Can you more fully explain beta?

A. The basic idea behind beta is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification. Beta is a measure of the

[3] Technically, Figure 1 from Duarte & Rosa plots the "first principal component" of the 20 models. This means that the authors used statistics to compute a weighted average that captures the most variability among the 20 models over time.

[4] Bloomberg as of December 12, 2016. As Bloomberg estimates the MRP over 10-year Treasury bonds, the equivalent figure over 20-year bonds is about 7.1% as the historical spread between 10-year and 20-year government bonds is a bit over 50 basis points from 1991 through today. For the historical MRP, see Duff & Phelps, *2016 Valuation Handbook - Guide to Cost of Capital*, Page 3-26.

risks that cannot be eliminated by diversification. That is, it measures the "systematic" risk of a stock—the extent to which a stock's value fluctuates more or less than average when the market fluctuates.

Diversification is a vital concept in the study of risk and return. (Harry Markowitz won a Nobel Prize for work showing just how important it was.) Over the long run, the rate of return on the stock market has a very high standard deviation, on the order of 20% per year.[5] Many individual stocks have much higher standard deviations than this. The stock market's standard deviation is "only" about 15-20% because when stocks are combined into portfolios, some of the risk of individual stocks is eliminated by diversification. Some stocks go up when others go down, and the average portfolio return—whether positive or negative—is usually less extreme than that of many individual stocks within it. The fact that the market's actual annual standard deviation is so large means that, in practice, the returns on stocks are positively correlated with one another, and to a material degree. The reason is that many factors that make a particular stock go up or down also affect other stocks. Examples include the state of the economy, the balance of trade, and inflation. Thus some risk is "non-diversifiable" in that even a well-diversified portfolio of stocks will experience changes in value caused by these shared risk factors. Single-factor equity risk premium models (such as the CAPM) are based upon the assumption that all of the systematic factors that affect stock returns can be considered simultaneously, through their impact on one factor: the market portfolio. Other models derive somewhat less restrictive conditions under which several factors might be individually relevant.

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[5] See Brealey, Myers and Allen (2011), *Principles of Corporate Finance*, 10th Edition, McGraw-Hill Irwin, New York, p. 166.

Again, the basic idea behind all of these models is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification, because there are a large number of large portfolios whose managers actively seek the best risk-reward tradeoffs available. (Of course, undiversified investors would like to get a premium for bearing diversifiable risk, but they cannot.)

Q. What does a particular value of beta signify?

A. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk: it goes up or down by 10% on average when the market goes up or down by 10%. Stocks with betas above 1.0 exaggerate the swings in the market: stocks with betas of 2.0 tend to fall 20% when the market falls 10%, for example. Stocks with betas below 1.0 are less volatile than the market. A stock with a beta of 0.5 will tend to rise 5% when the market rises 10%.

Q. How is beta measured?

A. The usual approach to calculating beta is a statistical comparison of the sensitivity of a stock's (or a portfolio's) return to the market's return. Many investment services report betas, including Bloomberg and the Value Line Investment Survey. Betas are not always calculated in precisely the same way, and therefore must be used with a degree of caution. However, the basic principle that a high beta indicates a risky stock has long been widely accepted by both financial theorists and investment professionals, and is universally reflected in all calculations of beta. In my analyses for these proceedings, I present results using the beta estimates reported by Value Line.

Q. What are the betas that you used for the sample companies?

A. Table 2 in my Direct Testimony showed the Value Line betas for the sample companies. The betas range from .65 to .95 with Portland General's beta of .70 being the same as the average.

4. The Empirical CAPM

Q. What other versions of the CAPM do you use?

A. 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.

This second model makes use of these empirical findings. It estimates the cost of capital with the equation,

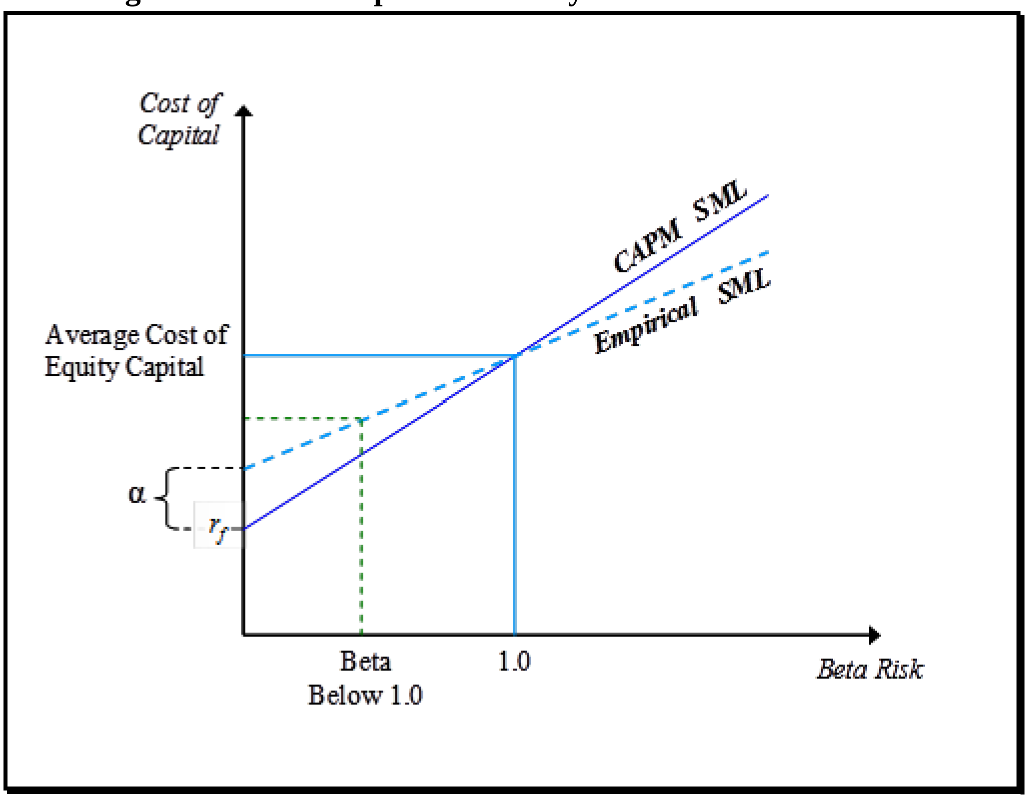
$$r_S = r_f + \alpha + \beta_S \times (MRP - \alpha) \qquad (2)$$

where α is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as 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 1 earlier in my testimony 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.

Q. Why is it appropriate to use the Empirical CAPM?

A. The CAPM has not generally performed well as an empirical model, but its short-comings are addressed by the ECAPM. As the ECAPM recognizes the empirical observation that the CAPM underestimates (overestimates) the cost of capital for low (high) beta stocks. In other words, the ECAPM is based on academic research that finds 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 observation. The difference between the CAPM and the type of relationship identified in the empirical studies is depicted in Figure 3-1 below.

Figure 3-1: The Empirical Security Market Line



<u>4. Unlevering and Relevering Betas in the CAPM (Hamada Adjustment)</u>

Q. What methods are available to take financial risk into account?

A. In addition to the after-tax weighted average cost of capital methodology 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.

Recognizing that under general conditions, the value of a firm can be decomposed into its value with and without a tax shield, I obtain:[6]

$$V = V_U + PV(ITS) \tag{3}$$

where $V = E + D$ is the total value of the firm,

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:

$$r_E = r_U + \frac{D}{E}(1 - \tau_c)(r_U - r_D) \tag{4}$$

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.

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)

[6] 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).

and the "unlevered" beta β_U that would be measured for the same firm if it had no debt in its capital structure:

$$\beta_L = \beta_U + \frac{D}{E}(1 - \tau_c)(\beta_U - \beta_D) \tag{5}$$

where β_D is the beta on the firm's debt. The unlevered beta is assumed to be constant with respect to capital structure, reflecting as it does the systematic risk of the firm's assets. Since the beta on an investment grade firm's debt is much lower than the beta of its assets (i.e., $\beta_D < \beta_U$), this equation embodies the fact that increasing financial leverage (and thereby increasing the debt to equity ratio) increases the systematic risk of *levered* equity (β_L).

An alternative formulation derived by Harris and Pringle (1985) provides the following equation that holds when the market value capital structures (rather than book value) are assumed to be held constant:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D) \tag{6}$$

Unlike Equation (5), Equation (6) 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. 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 (5), or Equation (6). Rather than estimating debt betas, I rely on the standard financial textbook of

Professors Berk and DeMarzo, who report a debt beta of 0.05 for A rated debt and a beta of 0.10 for BBB rated debt.[7]

Once a decision on debt betas is made, the levered equity beta of each sample company can be computed (in this case by Bloomberg) from market data and then translated to an unlevered beta at the company's market value capital structure. The unlevered betas for the sample companies are comparable on an "apples to apples" basis, since they reflect the systematic risk inherent in the assets of the sample 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.

Hamada adjustment procedures—so-named for Professor Robert S. Hamada who contributed to their development[8]—are ubiquitous among finance practitioners when using the CAPM to estimate discount rates. They are also utilized by many regulatory bodies. The U.K. Competition Commission as well as other U.K regulators and the Western Australia Economic Regulation Authority rely on an unlevering / relevering technique to determine the cost of equity capital for the entities they regulate.

Q. Can you summarize the results from applying the CAPM and ECAPM methodologies to the sample?

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[7] Berk, J. and DeMarzo, P., *Corporate Finance, 2nd Edition.* 2011 Prentice Hall, p. 389.
[8] 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.

A. The results of the risk positioning analyses (the CAPM and the ECAPM) are presented below in Table 3-1 using an α = 1.5% in the ECAPM. As was the case for the DCF results presented in Table 3 in my Direct Testimony, the ROE estimates below reflect the cost of equity estimate at PGE's regulatory capital structure.

Table 3-1: Cost of Equity Estimates Using CAPM and ECAPM
Return on Equity Summary and Sensitivity Analysis
U.S. Electric Sample and Subsample

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Full Sample		
Financial Risk Adjusted Method		
CAPM	9.6%	9.7%
ECAPM (α = 1.5%)	10.1%	10.2%
Hamada Adjustment Without Taxes		
CAPM	9.6%	9.9%
ECAPM (α = 1.5%)	9.9%	10.1%
Hamada Adjustment With Taxes		
CAPM	9.3%	9.6%
ECAPM (α = 1.5%)	9.6%	9.9%
Subsample		
Financial Risk Adjusted Method		
CAPM	9.4%	9.5%
ECAPM (α = 1.5%)	9.9%	10.1%
Hamada Adjustment Without Taxes		
CAPM	9.5%	9.7%
ECAPM (α = 1.5%)	9.8%	10.0%
Hamada Adjustment With Taxes		
CAPM	9.2%	9.4%
ECAPM (α = 1.5%)	9.5%	9.8%

Sources and Notes:

Scenario 1: Long-Term Risk Free Rate of 3.89%, Long-Term Market Risk Premium of 6.90%.

Scenario 2: Long-Term Risk Free Rate of 3.34%, Long-Term Market Risk Premium of 7.90%.

Q. What conclusions do you draw from the CAPM / ECAPM results?

A. The CAPM / ECAPM cost of equity estimates shows a range of 9.2% to 10.2% with the bulk of estimates being in the range of 9.5% - 10.1%.

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RESULTS FROM THE CAPM

Table No. BV-ELEC-9

Risk Free Rate

[1]	Consensus 10-Year Forecast	2.80%
	U.S. Government Bond Yields	
[2]	20-Year	5.02%
[3]	10-Year	4.48%
[4]	Maturity Premium	0.54%
[5]	Consensus 10-Year Forecast Adjusted to 20-year Horizon	3.34%

Sources and Notes:
[1]: Bluechip Consensus Forecast in October 2016.
[2]-[3]: Supporting Schedule # 1 to Table No. BV-ELEC-9. Averages of monthly bond yields from August 1991 through August 2016.
[4]: [2] - [3].
[5]: [1] + [4].

Table No. BV-ELEC-10

Risk Positioning Cost of Equity of the U.S. Electric Sample

el A: Scenario 1 - Long-Term Risk Free Rate of 3.89%, Long-Term Market Risk Premium of 6.9

Company	Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1 5%) Cost of Equity [5]
ALLETE	3 89%	0 75	6 90%	9 1%	9 4%
Alliant Energy	3 89%	0 70	6 90%	8 7%	9 2%
Amer Elec Power	3 89%	0 65	6 90%	8 4%	8 9%
Ameren Corp	3 89%	0 65	6 90%	8 4%	8 9%
CenterPoint Energy	3 89%	0 85	6 90%	9 8%	10 0%
CMS Energy Corp	3 89%	0 65	6 90%	8 4%	8 9%
Consol Edison	3 89%	0 55	6 90%	7 7%	8 4%
Dominion Resources	3 89%	0 65	6 90%	8 4%	8 9%
DTE Energy	3 89%	0 65	6 90%	8 4%	8 9%
Edison Int'l	3 89%	0 65	6 90%	8 4%	8 9%
El Paso Electric	3 89%	0 70	6 90%	8 7%	9 2%
Entergy Corp	3 89%	0 65	6 90%	8 4%	8 9%
IDACORP Inc	3 89%	0 75	6 90%	9 1%	9 4%
MGE Energy	3 89%	0 70	6 90%	8 7%	9 2%
OGE Energy	3 89%	0 90	6 90%	10 1%	10 3%
Otter Tail Corp	3 89%	0 85	6 90%	9 8%	10 0%
PG&E Corp	3 89%	0 65	6 90%	8 4%	8 9%
Pinnacle West Capital	3 89%	0 70	6 90%	8 7%	9 2%
Portland General	3 89%	0 70	6 90%	8 7%	9 2%
PPL Corp	3 89%	0 70	6 90%	8 7%	9 2%
Public Serv Enterprise	3 89%	0 70	6 90%	8 7%	9 2%
SCANA Corp	3 89%	0 70	6 90%	8 7%	9 2%
Sempra Energy	3 89%	0 80	6 90%	9 4%	9 7%
Vectren Corp	3 89%	0 75	6 90%	9 1%	9 4%
Xcel Energy Inc	3 89%	0 60	6 90%	8 0%	8 6%
Average				8 7%	9 2%
Subsample Average				8 7%	9 1%

Sources and Notes:
[1]: Villadsen Direct Testimony
[2]: Bloomberg as of December 8, 2016
[3]: Villadsen Direct Testimony
[4]: [1] + ([2] x [3])
[5]: ([1] + 1 5%) + [2] x ([3] - 1 5%)

Table No. BV-ELEC-10

Risk Positioning Cost of Equity of the U.S. Electric Sample

el B: Scenario 2 - Long-Term Risk Free Rate of 3.34%, Long-Term Market Risk Premium of 7.9

Company	Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1 5%) Cost of Equity [5]
ALLETE	3 34%	0 75	7 90%	9 3%	9 6%
Alliant Energy	3 34%	0 70	7 90%	8 9%	9 3%
Amer Elec Power	3 34%	0 65	7 90%	8 5%	9 0%
Ameren Corp	3 34%	0 65	7 90%	8 5%	9 0%
CenterPoint Energy	3 34%	0 85	7 90%	10 1%	10 3%
CMS Energy Corp	3 34%	0 65	7 90%	8 5%	9 0%
Consol Edison	3 34%	0 55	7 90%	7 7%	8 4%
Dominion Resources	3 34%	0 65	7 90%	8 5%	9 0%
DTE Energy	3 34%	0 65	7 90%	8 5%	9 0%
Edison Int'l	3 34%	0 65	7 90%	8 5%	9 0%
El Paso Electric	3 34%	0 70	7 90%	8 9%	9 3%
Entergy Corp	3 34%	0 65	7 90%	8 5%	9 0%
IDACORP Inc	3 34%	0 75	7 90%	9 3%	9 6%
MGE Energy	3 34%	0 70	7 90%	8 9%	9 3%
OGE Energy	3 34%	0 90	7 90%	10 5%	10 6%
Otter Tail Corp	3 34%	0 85	7 90%	10 1%	10 3%
PG&E Corp	3 34%	0 65	7 90%	8 5%	9 0%
Pinnacle West Capital	3 34%	0 70	7 90%	8 9%	9 3%
Portland General	3 34%	0 70	7 90%	8 9%	9 3%
PPL Corp	3 34%	0 70	7 90%	8 9%	9 3%
Public Serv Enterprise	3 34%	0 70	7 90%	8 9%	9 3%
SCANA Corp	3 34%	0 70	7 90%	8 9%	9 3%
Sempra Energy	3 34%	0 80	7 90%	9 7%	10 0%
Vectren Corp	3 34%	0 75	7 90%	9 3%	9 6%
Xcel Energy Inc	3 34%	0 60	7 90%	8 1%	8 7%
Average				8 9%	9 3%
Subsample Average				8 8%	9 3%

Sources and Notes:
[1]: Villadsen Direct Testimony
[2]: Bloomberg as of December 8, 2016
[3]: Villadsen Direct Testimony
[4]: [1] + ([2] x [3])
[5]: ([1] + 1 5%) + [2] x ([3] - 1 5%)

Table No. BV-ELEC-11

Overall After-Tax Cost of Capital of the U.S. Electric Sample

Panel A: CAPM Cost of Equity Scenario 1 - Long-Term Risk Free Rate of 3.89%, Long-Term Market Risk Premium of 6.90%

Company		CAPM Cost of Equity [1]	ECAPM (1 5%) Cost of Equity [2]	5-Year Average Common Equity to Market Value Ratio [3]	Weighted - Average Cost of Preferred Equity [4]	5-Year Average Preferred Equity to Market Value Ratio [5]	Weighted- Average Cost of Debt [6]	5-Year Average Debt to Market Value Ratio [7]	POR Representative Income Tax Rate [8]	Overall After-Tax Cost of Capital (CAPM) [9]	Overall After-Tax Cost of Capital (ECAPM 1 5%) [10]
ALLETE		9 1%	9 4%	60 3%	-	0 0%	4 58%	39 7%	39 9%	6 6%	6 8%
Alliant Energy	*	8 7%	9 2%	58 6%	4 30%	2 1%	4 30%	39 4%	39 9%	6 2%	6 5%
Amer Elec Power	*	8 4%	8 9%	53 6%	-	0 0%	4 58%	46 4%	39 9%	5 8%	6 0%
Ameren Corp	*	8 4%	8 9%	54 9%	-	0 0%	4 58%	45 1%	39 9%	5 8%	6 1%
CenterPoint Energy		9 8%	10 0%	49 0%	-	0 0%	4 30%	51 0%	39 9%	6 1%	6 2%
CMS Energy Corp	*	8 4%	8 9%	45 6%	-	0 0%	4 58%	54 4%	39 9%	5 3%	5 6%
Consol Edison	*	7 7%	8 4%	57 2%	-	0 1%	4 23%	42 7%	39 9%	5 5%	5 9%
Dominion Resources		8 4%	8 9%	59 6%	4 23%	0 3%	4 30%	40 1%	39 9%	6 0%	6 4%
DTE Energy	*	8 4%	8 9%	57 2%	-	0 0%	4 58%	42 8%	39 9%	6 0%	6 3%
Edison Int'l		8 4%	8 9%	52 4%	4 58%	5 6%	4 58%	42 0%	39 9%	5 8%	6 1%
El Paso Electric	*	8 7%	9 2%	55 8%	-	0 0%	4 58%	44 2%	39 9%	6 1%	6 3%
Entergy Corp	*	8 4%	8 9%	48 2%	4 58%	1 1%	4 58%	50 8%	39 9%	5 5%	5 7%
IDACORP Inc	*	9 1%	9 4%	59 3%	-	0 0%	4 58%	40 7%	39 9%	6 5%	6 7%
MGE Energy		8 7%	9 2%	74 9%	-	0 0%	4 05%	25 1%	39 9%	7 1%	7 5%
OGE Energy	*	10 1%	10 3%	66 9%	-	0 0%	4 30%	33 1%	39 9%	7 6%	7 7%
Otter Tail Corp	*	9 8%	10 0%	64 3%	4 58%	0 4%	4 58%	35 4%	39 9%	7 3%	7 4%
PG&E Corp	*	8 4%	8 9%	56 4%	4 58%	0 7%	4 58%	42 9%	39 9%	5 9%	6 2%
Pinnacle West Capital	*	8 7%	9 2%	60 9%	-	0 0%	4 37%	39 1%	39 9%	6 3%	6 6%
Portland General	*	8 7%	9 2%	52 0%	-	0 0%	4 58%	48 0%	39 9%	5 9%	6 1%
PPL Corp	*	8 7%	9 2%	45 8%	-	0 0%	4 44%	54 2%	39 9%	5 4%	5 6%
Public Serv Enterprise		8 7%	9 2%	64 7%	-	0 0%	4 58%	35 3%	39 9%	6 6%	6 9%
SCANA Corp		8 7%	9 2%	52 9%	-	0 0%	4 58%	47 1%	39 9%	5 9%	6 1%
Sempra Energy		9 4%	9 7%	59 2%	4 58%	0 1%	4 58%	40 6%	39 9%	6 7%	6 9%
Vectren Corp	*	9 1%	9 4%	61 7%	-	0 0%	4 23%	38 3%	39 9%	6 6%	6 8%
Xcel Energy Inc	*	8 0%	8 6%	53 6%	-	0 0%	4 23%	46 4%	39 9%	5 5%	5 8%
Full Sample Average		8 7%	9 2%	57 0%	4 5%	0 4%	4 5%	42 6%	39 9%	6 2%	6 4%
Subsample Average		8 7%	9 1%	56 0%	4 5%	0 3%	4 5%	43 7%	39 9%	6 1%	6 3%

Sources and Notes:
[1]: Table No BV-ELEC-10; Panel A, [4]
[2]: Table No BV-ELEC-10; Panel A, [5]
[3]: Table No BV-ELEC-4, [4]
[4]: Supporting Schedule #2 to Table No BV-ELEC-11, Panel
[5]: Table No BV-ELEC-4, [5]
[6]: Supporting Schedule #2 to Table No BV-ELEC-11, P
[7]: Table No BV-ELEC-4, [6]
[8]: AMLP Effective Corporate Tax Rate
[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])}
[9]-[10] 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 100 basis points

Table No. BV-ELEC-11

Overall After-Tax Cost of Capital of the U.S. Electric Sample

Panel B: CAPM Cost of Equity Scenario 2 - Long-Term Risk Free Rate of 3.34%, Long-Term Market Risk Premium of 7.90%

Company		CAPM Cost of Equity [1]	ECAPM (1 5%) Cost of Equity [2]	5-Year Average Common Equity to Market Value Ratio [3]	Weighted - Average Cost of Preferred Equity [4]	5-Year Average Preferred Equity to Market Value Ratio [5]	Weighted-Average Cost of Debt [6]	5-Year Average Debt to Market Value Ratio [7]	POR Representative Income Tax Rate [8]	Overall After-Tax Cost of Capital (CAPM) [9]	Overall After-Tax Cost of Capital (ECAPM 1 5%) [10]
ALLETE		9 3%	9 6%	60 3%	-	0 0%	4 58%	39 7%	39 9%	6 7%	6 9%
Alliant Energy	*	8 9%	9 3%	58 6%	4 30%	2 1%	4 30%	39 4%	39 9%	6 3%	6 6%
Amer Elec Power	*	8 5%	9 0%	53 6%	-	0 0%	4 58%	46 4%	39 9%	5 8%	6 1%
Ameren Corp	*	8 5%	9 0%	54 9%	-	0 0%	4 58%	45 1%	39 9%	5 9%	6 2%
CenterPoint Energy		10 1%	10 3%	49 0%	-	0 0%	4 30%	51 0%	39 9%	6 2%	6 4%
CMS Energy Corp	*	8 5%	9 0%	45 6%	-	0 0%	4 58%	54 4%	39 9%	5 4%	5 6%
Consol Edison	*	7 7%	8 4%	57 2%	-	0 1%	4 23%	42 7%	39 9%	5 5%	5 9%
Dominion Resources		8 5%	9 0%	59 6%	4 23%	0 3%	4 30%	40 1%	39 9%	6 1%	6 4%
DTE Energy	*	8 5%	9 0%	57 2%	-	0 0%	4 58%	42 8%	39 9%	6 0%	6 3%
Edison Int'l		8 5%	9 0%	52 4%	4 58%	5 6%	4 58%	42 0%	39 9%	5 9%	6 1%
El Paso Electric	*	8 9%	9 3%	55 8%	-	0 0%	4 58%	44 2%	39 9%	6 2%	6 4%
Entergy Corp	*	8 5%	9 0%	48 2%	4 58%	1 1%	4 58%	50 8%	39 9%	5 5%	5 8%
IDACORP Inc	*	9 3%	9 6%	59 3%	-	0 0%	4 58%	40 7%	39 9%	6 6%	6 8%
MGE Energy		8 9%	9 3%	74 9%	-	0 0%	4 05%	25 1%	39 9%	7 3%	7 6%
OGE Energy	*	10 5%	10 6%	66 9%	-	0 0%	4 30%	33 1%	39 9%	7 8%	7 9%
Otter Tail Corp	*	10 1%	10 3%	64 3%	4 58%	0 4%	4 58%	35 4%	39 9%	7 5%	7 6%
PG&E Corp	*	8 5%	9 0%	56 4%	4 58%	0 7%	4 58%	42 9%	39 9%	6 0%	6 3%
Pinnacle West Capital	*	8 9%	9 3%	60 9%	-	0 0%	4 37%	39 1%	39 9%	6 4%	6 7%
Portland General	*	8 9%	9 3%	52 0%	-	0 0%	4 58%	48 0%	39 9%	5 9%	6 2%
PPL Corp	*	8 9%	9 3%	45 8%	-	0 0%	4 44%	54 2%	39 9%	5 5%	5 7%
Public Serv Enterprise		8 9%	9 3%	64 7%	-	0 0%	4 58%	35 3%	39 9%	6 7%	7 0%
SCANA Corp		8 9%	9 3%	52 9%	-	0 0%	4 58%	47 1%	39 9%	6 0%	6 2%
Sempra Energy		9 7%	10 0%	59 2%	4 58%	0 1%	4 58%	40 6%	39 9%	6 8%	7 0%
Vectren Corp	*	9 3%	9 6%	61 7%	-	0 0%	4 23%	38 3%	39 9%	6 7%	6 9%
Xcel Energy Inc	*	8 1%	8 7%	53 6%	-	0 0%	4 23%	46 4%	39 9%	5 5%	5 8%
Full Sample Average		8 9%	9 3%	57 0%	4 5%	0 4%	4 5%	42 6%	39 9%	6 2%	6 5%
Subsample Average		8 8%	9 3%	56 0%	4 5%	0 3%	4 5%	43 7%	39 9%	6 2%	6 4%

Sources and Notes:
[1]: Table No BV-ELEC-10; Panel B, [4]
[2]: Table No BV-ELEC-10; Panel B, [5]
[3]: Table No BV-ELEC-4, [4]
[4]: Supporting Schedule #2 to Table No BV-ELEC-11, Panel
[5]: Table No BV-ELEC-4, [5]
[6]: Supporting Schedule #2 to Table No BV-ELEC-11, P
[7]: Table No BV-ELEC-4, [6]
[8]: AMLP Effective Corporate Tax Rate
[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])}
[9]-[10] 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 100 basis points

Table No. BV-ELEC-12

Risk Positioning Cost of Equity at Representative Deemed Capital Structure

	Tax Cost of [1]	Tax Cost of [2]	Representative [3]	Cost of BBB- [4]	Representative [5]	Representative [6]	Return on [7]	Return on [8]
Full Sample:								
CAPM	6.2%	6.2%	50.0%	4.6%	39.9%	50.0%	9.6%	9.7%
ECAPM (1.50%)	6.4%	6.5%	50.0%	4.6%	39.9%	50.0%	10.1%	10.2%
Subsample:								
CAPM	6.1%	6.2%	50.0%	4.6%	39.9%	50.0%	9.4%	9.5%
ECAPM (1.50%)	6.3%	6.4%	50.0%	4.6%	39.9%	50.0%	9.9%	10.1%

Sources and Notes:

[1]: Table No. BV-ELEC-11; Panel A, [9] - [10].

[2]: Table No. BV-ELEC-11; Panel B, [9] - [10].

[3]: AMLP Assumed Capital Structure.

[4]: Based on a BBB rating. Yield from Bloomberg as of December 8, 2016.

[5]: AMLP Effective Corporate Tax Rate.

[6]: AMLP Assumed Capital Structure.

[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 3.89%, Long-Term Market Risk Premium of 6.90%.

Scenario 2: Long-Term Risk Free Rate of 3.34%, Long-Term Market Risk Premium of 7.90%.

Table No. BV-ELEC-13

Hamada Adjustment to Obtain Unlevered Asset Beta

Company	Value Line Betas [1]	Debt Beta [2]	5-Year Average Common Equity to Market Value Ratio [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	5-Year Average Debt to Market Value Ratio [5]	POR Representative Income Tax Rate [6]	Asset Beta: Without Taxes [7]	Asset Beta: With Taxes [8]
ALLETE	0.75	0.10	60.3%	0.0%	39.7%	39.9%	0.49	0.57
Alliant Energy	0.70	0.06	58.6%	2.1%	39.4%	39.9%	0.43	0.50
Amer. Elec. Power	0.65	0.10	53.6%	0.0%	46.4%	39.9%	0.39	0.46
Ameren Corp.	0.65	0.10	54.9%	0.0%	45.1%	39.9%	0.40	0.47
CenterPoint Energy	0.85	0.06	49.0%	0.0%	51.0%	39.9%	0.45	0.55
CMS Energy Corp.	0.65	0.10	45.6%	0.0%	54.4%	39.9%	0.35	0.42
Consol. Edison	0.55	0.05	57.2%	0.1%	42.7%	39.9%	0.34	0.40
Dominion Resources	0.65	0.06	59.6%	0.3%	40.1%	39.9%	0.41	0.48
DTE Energy	0.65	0.10	57.2%	0.0%	42.8%	39.9%	0.41	0.48
Edison Int'l	0.65	0.10	52.4%	5.6%	42.0%	39.9%	0.39	0.45
El Paso Electric	0.70	0.10	55.8%	0.0%	44.2%	39.9%	0.43	0.51
Entergy Corp.	0.65	0.10	48.2%	1.1%	50.8%	39.9%	0.36	0.43
IDACORP Inc.	0.75	0.10	59.3%	0.0%	40.7%	39.9%	0.49	0.56
MGE Energy	0.70	0.05	74.9%	0.0%	25.1%	39.9%	0.54	0.59
OGE Energy	0.90	0.06	66.9%	0.0%	33.1%	39.9%	0.62	0.71
Otter Tail Corp.	0.85	0.10	64.3%	0.4%	35.4%	39.9%	0.58	0.66
PG&E Corp.	0.65	0.10	56.4%	0.7%	42.9%	39.9%	0.41	0.47
Pinnacle West Capital	0.70	0.07	60.9%	0.0%	39.1%	39.9%	0.45	0.52
Portland General	0.70	0.10	52.0%	0.0%	48.0%	39.9%	0.41	0.49
PPL Corp.	0.70	0.08	45.8%	0.0%	54.2%	39.9%	0.36	0.44
Public Serv. Enterprise	0.70	0.10	64.7%	0.0%	35 3%	39.9%	0.49	0.55
SCANA Corp.	0.70	0.10	52.9%	0.0%	47.1%	39.9%	0.42	0.49
Sempra Energy	0.80	0.10	59.2%	0.1%	40.6%	39.9%	0.51	0.59
Vectren Corp.	0.75	0.05	61.7%	0.0%	38.3%	39.9%	0.48	0.56
Xcel Energy Inc.	0.60	0.05	53.6%	0.0%	46.4%	39.9%	0.34	0.41
Full Sample Average	0.70	0.08	57.0%	0.4%	42.6%	39.9%	0.44	0.51
Subsample Average	0.69	0.08	56.0%	0.3%	43.7%	39.9%	0.43	0.50

Sources and Notes:
[1]: Supporting Schedule # 1 to Table No. BV-ELEC-10, [1].
[2]: Supporting Schedule #1 to Table No. BV-ELEC-13, [7].
[3]: Table No. BV-ELEC-4, [4].
[4]: Table No. BV-ELEC-4, [5].
[5]: Table No. BV-ELEC-4, [6].
[6]: AMLP Effective Corporate Tax Rate
[7]: [1]*[3] + [2]*([4] + [5]).
[8]: {[1]*[3] + [2]*([4]+[5]*(1-[6]))} / {[3] + [4] + [5]*(1 -[6])}.

Table No. BV-ELEC-14

Sample Average Asset Beta Relevered at Representative Deemed Capital Structure

	Asset Beta [1]	Assumed Debt Beta [2]	POR Representative Base Deemed % Debt [3]	POR Representative Income Tax Rate [4]	POR Representative Base Deemed % Equity [5]	Estimated Equity Beta [6]
Full Sample:						
Asset Beta Without Taxes	0.44	0.05	50.0%	39.9%	50.0%	0.83
Asset Beta With Taxes	0.51	0.05	50.0%	39.9%	50.0%	0.79
Subsample:						
Asset Beta Without Taxes	0.43	0.05	50.0%	39.9%	50.0%	0.81
Asset Beta With Taxes	0.50	0.05	50.0%	39.9%	50.0%	0.77

Sources and Notes:
[1]: Table No. BV-ELEC-13, [7] - [8].
[2]: Debt Beta estimate for BBB-rated entities.Corporate Finance, Berk and Demarzo, Second Edition, p. 389.
[3]: AMLP Assumed Capital Structure.
[4]: AMLP Effective Corporate Tax Rate.
[5]: AMLP Assumed Capital Structure.
[6]: [1] + [3]/[5]*([1] - [2]) without taxes, [1] + [3]*(1 - [4])/[5]*([1] - [2]) with taxes.

Table No. BV-ELEC-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel A: Scenario 1 - Long-Term Risk Free Rate of 3.89%, Long-Term Market Risk Premium of 6.90%

Company	Long-Term Risk-Free Rate [1]	Hamada Adjusted Equity Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Asset Beta Without Taxes	3.89%	0.83	6.90%	9.6%	9.9%
Asset Beta With Taxes	3.89%	0.79	6.90%	9.3%	9.6%
Subsample:					
Asset Beta Without Taxes	3.89%	0.81	6.90%	9.5%	9.8%
Asset Beta With Taxes	3.89%	0.77	6.90%	9.2%	9.5%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Table No. BV-ELEC-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-ELEC-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel B: Scenario 2 - Long-Term Risk Free Rate of 3.34%, Long-Term Market Risk Premium of 7.90%

Company	Long-Term Risk-Free Rate [1]	Hamada Adjusted Equity Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Asset Beta Without Taxes	3.34%	0.83	7.90%	9.9%	10.1%
Asset Beta With Taxes	3.34%	0.79	7.90%	9.6%	9.9%
Subsample:					
Asset Beta Without Taxes	3.34%	0.81	7.90%	9.7%	10.0%
Asset Beta With Taxes	3.34%	0.77	7.90%	9.4%	9.8%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Table No. BV-ELEC-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Parameters Used in CAPM-based Models

	Scenario 1	Scenario 2
Risk-Free Interest Rate	3.9%	3.3%
Market Equity Risk Premium	6.9%	7.9%

EXHIBIT PGE 1105

AUTHORIZED ROE FOR INTEGRATED ELECTRIC UTILITIES

PGE Exhibit 1105
Allowed Returns on Equity for Vertically Integrated Electrics in 2016

Average	Median	Minimum	Maximum
9.77	9.78	9.37	10.55

Source: SNL Financial as of 1/9/2017

EXHIBIT PGE 1106

YIELD SPREADS

Spreads between U.S. Utility Bond (20 year maturity) and U.S. Government Bond (20 year maturity) - %			
Periods	A-Rated Utility and Treasury	BBB-Rated Utility and Treasury	Notes
Period 1 - Average Apr-1991 - 2007	0.93	1.23	[1]
Period 2 - Average Aug-2008 - Nov-2016	1.54	2.02	[2]
Period 3 - Average Nov-2016	1.72	2.21	[3]
Period 4 - Average 15-Day (Nov 15, 2016 to Dec 06, 2016)	1.51	1.99	[4]
Spread Increase between Period 2 and Period 1	0.61	0.79	[5] = [2] - [1]
Spread Increase between Period 3 and Period 1	0.78	0.98	[6] = [3] - [1]
Spread Increase between Period 4 and Period 1	**0.58**	**0.76**	[7] = [4] - [1]

Sources and Notes:

Spreads for the periods are calculated from Bloomberg's yield data.

Average monthly yields for the indices were retrieved from Bloomberg as of December 7, 2016.

EXHIBIT PGE 1107

P/E AND PAYOUT RATIOS

PGE Exhibit 1107
P/E Ratio Analysis - Regression Output

_id	ticker	r2	N	coefA	stderrA	tstatA	pvalA	coefB	stderrB	tstatB	pvalB
1		0.026121	2300	24.49852	0.937587	26.12932	5.4093E-132	-1.363704	0.173702	-7.850836	6.2847E-15
2	electric_average	0.182787	107	24.72097	1.57882	15.65788	3.19039E-29	-1.386652	0.286133	-4.846174	4.3689E-06
3	electric_median	0.171882	107	19.6108	1.180024	16.61898	3.64106E-31	-0.998368	0.213859	-4.668354	9.0111E-06
4	subsample_average	0.167341	107	26.57248	1.866426	14.2371	2.9174E-26	-1.553852	0.338257	-4.593704	1.2154E-05
5	subsample_median	0.118918	107	19.23775	1.297936	14.8218	1.7133E-27	-0.885522	0.235228	-3.764528	0.00027536

PGE Exhibit 1107
P/E Ratio Analysis - Dividend Payouts

Company	All Dividends to Net Profits
ALLETE	60%
Alliant Energy	65%
Amer. Elec. Power	60%
Ameren Corp.	70%
CenterPoint Energy	92%
CMS Energy Corp.	61%
Consol. Edison	61%
Dominion Resources	81%
DTE Energy	63%
Edison Int'l	44%
El Paso Electric	57%
Entergy Corp.	58%
IDACORP Inc.	50%
MGE Energy	56%
OGE Energy	61%
Otter Tail Corp.	79%
PG&E Corp.	88%
Pinnacle West Capital	59%
Portland General	56%
PPL Corp.	63%
Public Serv. Enterprise	47%
SCANA Corp.	57%
Sempra Energy	48%
Vectren Corp.	65%
Xcel Energy Inc.	57%
Minimum	44%
Maximum	92%
Median	60%
Average	62%

Source:
Value Line as of December 8th, 2016

RESUME OF DR. BENTE VILLADSEN

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent advisory work is the review of regulatory practices regarding the return on equity, capital structure, recovery of costs and capital expenditures 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 railroad 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, she was a Professor of Accounting at the University of Iowa, University of Michigan, and at Washington University in St. Louis where she taught accounting. She has also taught graduate classes in econometrics and quantitative methods. Dr. Villadsen also worked as a consultant for Risoe National Laboratories in Denmark.

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

  - Credit Issues in the Utility Industry
- Damages and Valuation
  - Utility valuation
  - Lost Profit

EXPERIENCE

Regulatory Finance

- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board and submitted expert reports on the determination of the cost of equity for U.S. freight railroads.

- For several electric, gas and transmission utilities 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.

- 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.

- She has estimated the cost of equity on behalf of Anchorage Municipal Light and Power, Arizona Public Service, Portland General Electric, Anchorage Water and Wastewater, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony before the 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.
- For 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.
- 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

- On behalf of a construction company in arbitration with a sovereign, Dr. Villadsen filed an expert 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.
- 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 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.

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"Current Issues in Cost of Capital," *Edison Electric Institute Advanced Rate School*, July 2016, 2015, 2014 and 2013.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Sarah Dammen
Amber Riter

February 28, 2017

Table of Contents

I. Introduction and Summary

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

A. My name is Sarah J. Dammen. I am the Manager of Financial Forecasting and Economic Analysis at PGE.

My name is Amber M. Riter. I am an Economist and the Lead Load Forecast Analyst at PGE.

We are responsible for developing PGE's energy deliveries forecast. Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony presents PGE's 2018 test year energy and customer forecast. We note that we use the terms "energy deliveries" and "load forecast" interchangeably in this testimony.

Q. What load forecast related request does PGE make of the Commission in this proceeding?

A. We request the Commission: 1) accept as a preliminary matter our forecast of energy deliveries which reflects methodological and modeling changes described below; and 2) set a schedule in this proceeding allowing for periodic updates of the energy delivery forecast for 2018.

Q. Please describe PGE's delivery forecast.

A. PGE's 2018 test year energy forecast is for energy deliveries of 19,124 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 and 489. The forecast reflects current expected economic conditions for Oregon in 2018, as well as operational changes among PGE's largest customers and savings from incremental energy efficiency (EE) programs that are funded through Schedule 109 Incremental EE Funding per Senate Bill 838 (SB 838).

Q. How does the 2018 forecast compare to recent historical demand?

A. Similar to the energy delivery trends of recent years, the 2018 forecast reflects stronger growth in deliveries to industrial (primary voltage service) customers relative to significantly lower growth anticipated in the residential and commercial customer classes. Industrial deliveries growth is related to high-tech expansion and new data centers; and while stronger than other customer classes, the rate of growth in deliveries to industrial customers has slowed as a large high-tech construction project nears completion.

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 2014 through 2018.

Table 1

Percent Change in MWh Delivery from Preceding Year: 2014-2018

Voltage Service Class	2014	2015	2016	2017 (E)	2018 (E)
Residential	0.1%	-0.7%	0.5%	-0.6%	0.0%
Secondary	1.7%	0.3%	-1.3%	-0.2%	-0.7%
Transmission	-21.9%	4.2%	-56.2%	-5.5%	-2.2%
Primary	8.3%	7.0%	1.5%	1.0%	2.5%
Street Lighting	-9.7%	-14.2%	-13.9%	-15.8%	-12.2%
Total	0.8%	1.2%	-2.6%	-0.3%	0.2%

Q. Does PGE adjust the base forecast for price elasticity effects?

A. No. PGE expects customers to respond to price increases by making behavioral changes to decrease usage in the short-term and making changes to the capital stock including purchasing more energy efficient appliances and equipment in the long term. However, as stipulated in PGE's 2016 General Rate Case (UE 294) no price elasticity adjustments are made to the 2018 test-year forecast.

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 SB 838, as forecasted by the Energy Trust of Oregon (ETO), and updated in November of 2016. Since EE trends, including Senate Bill 1149 (SB 1149)[1] measures, are assumed to be captured implicitly in the forecast model, no explicit adjustments are made for SB 1149 savings. The incremental EE program levels reflect the increased funding for EE programs under Senate Bill 838, starting in November 2016, the first month of the forecast. As stipulated in UE 262, PGE implemented a quarterly ramping of incremental EE savings to reflect the ETO's historic pattern of EE savings and updated the quarterly ramping to reflect the 5-year average of quarterly achieved savings from 2011 to 2015.

Q. What is the impact of incremental EE programs savings on the forecast?

A. We estimate a total of 301.7 thousand MWh or 1.6% savings from these programs in the 2018 test year based on the EE savings starting in November 2016 and accumulating through December 2018. PGE Exhibit 1202 shows the forecast adjusted for incremental EE savings and PGE Exhibit 1203 shows the savings from the incremental EE programs that are included in PGE's delivery forecast.

[1] Among other things, Oregon Senate Bill 1149 established the 3% public purpose charge to fund and encourage energy conservation.

II. Model and Forecast Process

Q. Please summarize the process you use to develop the retail energy delivery forecast.

A. We use monthly time-series regression models to estimate the residential, commercial and manufacturing sectors, based on the historic relationship between energy deliveries and economic variables, weather variables, and seasonal control variables. The most current forecasted explanatory variables are applied to the coefficients from the regression models to develop the energy delivery forecast.

Q. Are these models new or different from previous PGE energy delivery models?

A. No. The forecast models and process remain fundamentally the same as those used in previous filings with the Commission. PGE's past load forecast testimony describes, in detail, the theory and structure of our model, as well as our forecast processes. These were most recently submitted in PGE's 2017 Net Variable Power Cost filing[2] and 2016 General Rate Case[3].

Q. Does PGE intend to update its 2018 forecast during this case?

A. Yes, we intend to update the test-year forecast as we have in prior cases. Updates include model re-estimation to incorporate actual load and economic data as they become available and changes in forward looking inputs, including the economic outlook for the U.S. and Oregon, and any changes to large customers' usage forecasts.

Q. What sources of information do you use to forecast electricity deliveries?

A. PGE relies on two sources of economic information for the forecast: 1) IHS Global Insight for a national economic forecast; and 2) the Oregon Department of Administrative Services'

[2] See Docket No. UE 308, Load Forecast Work Papers
[3] See Docket No. UE 294, Exhibit 1200

Office of Economic Analysis (OEA) for the Oregon economic forecast. Global Insight's November 2016 forecast and OEA's December 2016 forecast were used to develop the forecast for this proceeding. In addition, customers who are large energy users provide us with specific operational information, direct inputs and, if available, forecasts of energy use. PGE's Corporate Finance Group performs credit-risk analysis for these large customers, providing additional credit-risk and financial performance information on our large customers.

Q. What assumption did you make regarding weather variables in the forecast?

A. The test-year forecast is based on a trended normal weather assumption to capture gradual warming observed in the Portland area over the last 40 years. The normal weather series is estimated using monthly degree day data from 1941 to 2015, with a simple average from 1941 to 1975 and a linear trend fit to data from 1976 to 2015.

Q. Is the assumption regarding weather variables used in the forecast different from that used in prior PGE forecasts?

A. Yes. Since UE 180, PGE has used a 15-year moving average to represent normal weather conditions.

Q. Why is PGE proposing a change in the weather forecast assumption?

A. PGE strives for an expected mid-point load forecast; that is, a "50/50" load forecast where there is a 50 percent chance that the actual outcome falls short of or exceeds the forecast. To achieve this, forecast assumptions must also be based on an expected mid-point, where it is equally likely that the outcome falls short of or exceeds the assumption. In the case of a persistent warming trend, as experienced in the Pacific Northwest, a moving average approach contains a cold bias[4] and does not achieve a 50/50 forecast. PGE proposes the trended weather approach to better approximate a 50/50 forecast for expected weather.

Q. Why is a trended approach recommended rather than a shortening of the time period used for the normal weather assumption?

A. The justification for using a 15-year moving average to represent normal weather conditions as presented in UE 180 was to better capture warming trends experienced in PGE's service area as compared to a 30-year moving average. Importantly, this approach balanced the need to minimize bias without subjecting PGE's models to increased volatility which can be associated with too short a time frame for a normal weather assumption. While the 15-year moving average is an improvement from a 30-year moving average, the trended weather approach can further reduce bias without sacrificing stability due to the long historical series used to estimate the expected weather. See PGE Exhibit 1211 for a comparison of these two approaches.

Q. How was this approach developed?

A. The trended normal weather approach used for the test year load forecast was developed in alignment with analysis published in several academic journals and used by the National Oceanic and Atmospheric Association (NOAA) to produce a trended series available through its Local Climate Analysis Tool (LCAT). *"Estimation and Extrapolation of Climate Normals and Climatic Trends"*[5] lays the groundwork for this approach and compares results to several alternatives. The authors find that their 'hinge-fit' model (i.e., the approach that PGE refers to as trended weather) outperforms a single straight line fit and optimal climate

[4] A cold bias in the weather assumptions means that we systematically underestimate average temperature.
[5] Livezey, Robert E. et al. "Estimation and Extrapolation of Climate Normals and Climatic Trends." Journal of Applied Meteorology and Climatology, vol. 46, 2007, pp. 1759-1776.

normal (shortened time period), making a strong case for the application of a hinge-fit model with a 1975 breakpoint (hinge) for much of the United States and Canada. An important condition for the application of the trended weather (hinge-fit) approach is that regional trends are “approximately linear” and that the 1975 breakpoint, which is applied in a standardized fashion based on climate scientist reports that the period of steady global warming began in the mid-1970s, is relevant to the region of interest. PGE’s analysis finds weather trends as measured at Portland International Airport meet the assumption of “approximately linear” and also finds 1975 to be generally consistent as a midpoint for breakpoint analysis.

Q. What are the primary impacts of this weather assumption on PGE’s load forecast results?

A. Using the trended weather assumption decreases PGE’s annual energy deliveries forecast by approximately 61.2 thousand MWh’s, or 0.3%, in 2018 compared to the use of a 15-year normal weather assumption. Within this total change is a seasonal shift in PGE’s energy deliveries, primarily to PGE’s residential customers, decreasing deliveries in the heating months and increasing deliveries in the cooling season.

Q. How does this weather assumption impact the weather adjustment used in PGE’s decoupling calculation?

A. The weather assumption, based on the trended weather approach, will be used for the weather adjustment in the decoupling calculation beginning in 2018. Using the trended weather normal for the weather adjustment is appropriate and has no impact on decoupling since the baseline use-per-customer would also be set using the trended weather forecast assumption. Per Special Condition 2 of PGE Schedule 123-6, “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."

Q. How current are the data you use to estimate the model?

A. The models estimated for use in this proceeding are based on data through the October 2016 billing cycle. The model estimation periods vary by forecast group with the estimation period shortened for many models based on analysis of the relationship between energy deliveries and the economic drivers in the models described in UE 294.

Q. What end-use sectors do you forecast in the model?

A. We forecast demand (MWh delivery) by residential, commercial, manufacturing customers and energy served under miscellaneous rate schedules. Residential customers are mostly households. We group commercial and manufacturing customers according to the North America Industrial Classification System (NAICS) definition of business segments. Commercial customers typically are businesses providing services, such as retail and wholesale establishments, schools, hospitals, government, and financial institutions. Manufacturing customers include producers of paper, lumber, steel, machinery, micro-processors, computers, and transportation equipment.

Q. How do you forecast the ultimate loads delivered to the PGE system?

A. This process 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 end users' demand. For test year 2018, we apply updated line loss factors beginning in 2015 as established in UE 283.

Q. How do you forecast monthly net system peak demand?

A. Regression-based models are used to forecast PGE's monthly peak demand. The regression-based approach estimates monthly and seasonal peak demands as a function of peak day heating degree days, cooling degree days, prior day cooling degree days, average wind and monthly energy interacted with season. The coefficients are applied to forecasted monthly energy deliveries (MWa), weather variables and appropriate seasonal dummy variables to estimate the forecast. PGE Exhibit 1209 displays the forecast of total distribution loads in annual average energy (MWa) and peak demand (MW).

Q. Is this approach different from previous general rate case monthly peak demand models?

A. Yes. In prior forecasts, PGE used a load factor build-up approach where monthly voltage-level and system load factors were used to calculate the monthly peak MW based on the projected average energy (MWa). The difference between the annual net system peak demand under these two approaches is approximately 47 MW in 2018.

Q. What benefit does PGE see in using regression based peak demand models?

A. PGE proposes regression-based peak forecast models to align with recommendations made in the industry benchmarking performed by Itron in 2014 and referenced in testimony provided in UE 294. Regression-based models offer flexibility in addressing seasonal patterns exhibited in PGE's recent historical peaks apart from modeling of seasonal trends in the energy models. This approach also allows for a more direct analysis of the impact of extreme weather events on PGE loads. The regression-based models were reviewed with stakeholders in PGE's 2016 Integrated Resource Plan (IRP) public process with a workshop held in July 2015.

III. Forecast Results

Q. What are the key results of PGE's residential sector forecast?

A. For the test year 2018, we forecast deliveries of 7,563 thousand MWh to 772,010 residential customers. Declines in residential use per customer, driven by assumed incremental energy efficiency programs, are offset by customer growth of 1.3% in 2018 for annual residential energy deliveries growth of 0.0%. The residential forecast includes residential outdoor area lighting energy. PGE Exhibit 1204 shows the forecast of building permits, new connects, and customer counts. PGE Exhibit 1205 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 test year 2018, we forecast deliveries of 6,819 thousand MWh to NAICS-based commercial customers, a 0.9% decrease over forecasted 2017 energy deliveries of 6,878 thousand MWh. Declining energy deliveries to the commercial NAICS groups reflect savings from incremental EE programs larger than those projected in the residential sector, impacting the NAICS-based commercial sector by -2.5% for 2018. PGE Exhibit 1206 contains the detailed forecast of deliveries to commercial consumers.

Q. What are the key results of PGE's manufacturing sector forecast?

A. For the test year 2018, we forecast deliveries of 4,589 thousand MWh to NAICS-based manufacturing customers, 2.0% higher than forecasted 2017 deliveries, following growth of 6.3% in 2015 and a decline of 9.1% in 2016. The manufacturing forecast reflects continued expansion by high-tech and related companies in our service territory (on primary voltage service). Manufacturing sector deliveries can show large swings from year to year due to specific individual company operations and industry conditions. PGE Exhibit 1207 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 approximately 1% of total retail deliveries in 2018. PGE Exhibit 1208 displays the miscellaneous schedules forecast.

Q. Did you make a separate forecast of delivery to Rate Schedule 485/489 customers?

A. Yes. PGE separates the delivery of energy to customers who chose service under Schedule 485/489 (direct access) by 2016 year-end from the energy delivery forecast to customers served under PGE cost-of-service (COS) rates, including variable-price (market power) customers. Schedule 485/489 is the only service under which we forecast customers to receive direct access service in 2018. 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. PGE Exhibit 1210 shows the forecast of deliveries in 2018 to PGE COS customers and direct access (Schedule 485/489) customers.

V. Forecast Uncertainty

Q. Is the forecast subject to uncertainty?

A. Yes. The MWh delivery forecast we submit in this filing is our "expected" or mid-point estimate but is subject to uncertainty. As such, it is a 50/50 "point" forecast, 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.

As mentioned with respect to the proposed trended weather approach, the accuracy of a forecast depends not only on the performance of the model specification, but also on the accuracy of the independent variables driving the forecast. In our model, the independent variables include weather variables and the economic forecast drivers.

The other major areas of uncertainty involve inputs and assumptions surrounding implementation of EE programs, key customers' operational decisions, new customers' entry or existing customers' exit, and the absence of unforeseen natural disasters, wars or geopolitical turmoil. Future outcomes of these variables could result in a significant variance from the forecast.

Q. How do you address uncertainty in your forecast?

A. PGE aims to use the best information available as input assumptions to reduce uncertainty and updates the forecast as conditions change. This includes using current information, sales data and forecast drivers. Conditions could and will likely change between the time PGE developed this forecast and the start of the test year. Our assumptions will be revisited as updated forecasts are released for input assumptions.

Q. Do changing economic conditions have an effect on PGE's forecast?

A. Yes. Changing economic conditions are an important source of uncertainty in PGE's delivery forecast. All else equal, economic outcomes that differ from the economic forecast assumption used to drive PGE's forecast of MWh delivery result in delivery outcomes that differ from the initial forecast. In addition to changing economic conditions, the changing relationship between economic conditions and energy deliveries can also affect the forecast.

The economic climate could also lead PGE's key customers to operate differently than planned. They could shut down plants, curtail operations, or add new capacity that we did not anticipate because of their own specific circumstances. In fact, since the onset of the Great Recession in 2008 a number of large customers have filed for bankruptcy, liquidated business, changed ownership or permanently shut down operations, which has substantially affected PGE's actual and anticipated MWh delivery. With respect to announced new developments, we specifically include in this forecast planned expansions and operational changes by high-tech and metals manufacturing customers. If any of these assumptions fail to materialize, significant deviations from the test year forecast would result. While the forecast is developed to account for both upside potential (expansion) as well as downside risk, the inherent risks are biased toward the downside because it takes longer for a customer to plan and increase capacity than to shut down.

Q. Is weather also an area of uncertainty?

A. Yes. In UE 180, PGE discussed extensively the uncertainty of the delivery forecast with regard to weather, in terms of the average or the mean condition and the variance or departure from the average condition in the forecast year. The impact of this uncertainty, expressed as deviation from the mean, is significant because of the large impact of temperature on MWh usage. The proposed trended weather approach addresses the mean condition; however weather will likely deviate from the assumed weather in any given year. PGE estimates that one degree variation in temperature could affect (total retail) MWh usage by as much as 1.5% in peak months and as much as 0.7% on an annual basis.

VI. Qualifications

Q. Ms. Dammen, please describe your qualifications.

A. I received my Bachelor of Arts and Master of Science, both in Economics from Oregon State University. I have been a practicing Economist for the past 13 years. I am currently a member of the Northwest Power Planning Council's Demand Forecasting Advisory Committees and have previously served on TriMet's General Manager's Budget Task Force. Prior to joining PGE in 2012, I worked at NW Natural, performing load forecasting and developing the IRP; I was an economic consultant at ECONorthwest, specializing in quantitative economics and transportation economics; and was an economist for the U.S. Department of Transportation at the Volpe Transportation Systems Center.

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 from The University of New Mexico. I have been working as an Economist in energy deliveries forecasting for the past 7 years. Prior to joining PGE in 2014, I worked at PNM Resources, the parent company of Public Service Company of New Mexico (PNM) and Texas New Mexico Power (TNMP), performing load forecasting and load research analysis.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1201	(Base) Delivery Forecast by Market Segment and Service Level
1202	(Post EE Adjustment) Delivery Forecast by Market Segment and Service Level
1203	Forecast of Incremental Energy Efficiency Program Savings
1204	Residential Building Permits, New Connects, and Customer Counts (Accounts)
1205	Forecast of Residential Use per Customer and Ultimate Deliveries
1206	Commercial Deliveries Forecast by NAICS Cluster
1207	Manufacturing Deliveries Forecast by NAICS Cluster
1208	Forecast of Deliveries to Miscellaneous Rate Schedules
1209	Total Deliveries and Demand Forecast
1210	Forecast of 2018 Deliveries to Cost-of Service and Direct Access Customers
1211	Trended Weather HDD and CDD Comparison
1212	Trended Weather Literature

Exhibit 1201: Delivery Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (not adjusted) Forecast (1)

	(in thousand MWh)					% Change (2)				
	2014	**2015**	**2016**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**
Schedule 7	7,613	7,563	7,600	7,599	7,661	0.2%	-0.7%	0.5%	0.0%	0.8%
Residential Lighting	5	3	3	3	3	-25.9%	-33.6%	-2.2%	1.3%	0.0%
Total Residential	7,618	7,567	7,604	7,602	7,664	0.1%	-0.7%	0.5%	0.0%	0.8%
Commercial (3)	6,994	6,988	6,920	6,948	6,985	1.2%	-0.1%	-1.0%	0.4%	0.5%
Manufacturing (3)	4,616	4,907	4,458	4,512	4,624	1.7%	6.3%	-9.1%	1.2%	2.5%
Miscellaneous Customers	193	190	166	160	154	-4.9%	-1.4%	-12.8%	-3.4%	-4.0%
Secondary Voltage	7,312	7,320	7,239	7,296	7,344	1.7%	0.1%	-1.1%	0.8%	0.7%
Total General Service	7,504	7,510	7,405	7,456	7,498	1.5%	0.1%	-1.4%	0.7%	0.6%
Primary Voltage Service	3,459	3,700	3,756	3,803	3,911	8.3%	7.0%	1.5%	1.2%	2.8%
Transmission Voltage Service	839	874	382	361	353	-21.9%	4.2%	-56.2%	-5.5%	-2.2%
Total Retail	19,420	19,651	19,147	19,222	19,426	0.8%	1.2%	-2.6%	0.4%	1.1%

1/ SDEC16B

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.

Exhibit 1202: Delivery Forecast (Price & Incremental EE) by Market Segment and Service Level

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency (1)

	(in thousand MWh)					% Change (2)				
	2014	**2015**	**2016 (3)**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**
Schedule 7	7,613	7,563	7,600	7,556	7,560	0.2%	-0.7%	0.5%	-0.6%	0.0%
Residential Lighting	5	3	3	3	3	-25.9%	-33.6%	-2.2%	1.3%	0.0%
Total Residential	7,618	7,567	7,604	7,560	7,563	0.1%	-0.7%	0.5%	-0.6%	0.0%
Commercial (3)	6,994	6,988	6,920	6,878	6,819	1.2%	-0.1%	-1.0%	-0.6%	-0.9%
Manufacturing (3)	4,616	4,907	4,458	4,497	4,589	1.7%	6.3%	-9.1%	0.9%	2.0%
Miscellaneous Customers	193	190	166	160	154	-4.9%	-1.4%	-12.8%	-3.4%	-4.0%
Secondary Voltage	7,312	7,320	7,239	7,220	7,166	1.7%	0.1%	-1.1%	-0.3%	-0.7%
Total General Service	7,504	7,510	7,405	7,380	7,320	1.5%	0.1%	-1.4%	-0.3%	-0.8%
Primary Voltage Service	3,459	3,700	3,756	3,793	3,888	8.3%	7.0%	1.5%	1.0%	2.5%
Transmission Voltage Service	839	874	382	361	353	-21.9%	4.2%	-56.2%	-5.5%	-2.2%
Total Retail	19,420	19,651	19,147	19,094	19,124	0.8%	1.2%	-2.6%	-0.3%	0.2%

1/ SDEC16E

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.

Exhibit 1203: Forecast of Incremental Energy Efficiency (EE) Savings

(in thousand MWh)

	2017	2018
Base (B) Forecast	19,222	19,426
Incremental EE Savings (1)	(128)	(302)
Post-EE Forecast (E) (2)	19,094	19,124

1/ Energy Trust of Oregon (ETO) annual savings deployment forecast.

2/Totals and differences may not foot due to rounding.

Exhibit 1204: Residential Building Permits, New Connects, Vacancy Rates and Customer Counts History and Forecast

	2014	2015	2016 (1, 2)	2017	2018
Building Permits (3)					
Single-Family	8,482	9,999	10,629	10,472	10,813
Multi-Family	7,372	6,371	8,082	8,129	8,597
New Connects					
Single-Family	3,259	4,480	5,291	5,737	5,849
Multi-Family	3,539	3,965	4,503	5,266	5,287
Mobile Home	49	64	112	60	60
Other	10	41	13	24	24
Total Residential Connects	6,857	8,550	9,919	11,087	11,220
Commercial Connects	1,669	1,935	2,025	2,136	2,141
Total New Connects	8,526	10,485	11,944	13,223	13,361
Residential Customer Counts					
Single-Family Heat	109,246	109,572	110,374	110,730	111,083
Single-Family Non-Heat	350,673	354,075	358,731	362,999	367,473
Multiple-Family Heat	178,802	180,880	184,326	188,476	192,087
Multiple-Family Non-Heat	57,604	58,743	59,641	60,929	62,484
Mobile Home Heat	30,401	30,417	30,501	30,335	30,147
Mobile Home Non-Heat	3,886	3,908	3,932	3,922	3,904
Other	4,892	4,872	4,883	4,860	4,831
Total Number of Accounts (4)	735,504	742,467	752,388	762,251	772,010

1/ includes actuals through December 2016, except for connects which include actuals through November 2016

2/ forecasted values are identical for base, price-effect and energy efficiency forecast

3/ Oregon building permits

4/ includes vacant accounts

Exhibit 1205: Forecast of Residential Use per Occupied Account and Ultimate Deliveries

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency (1)

	2014 (2)	2015 (2)	2016 (2)	2017	2018
Use per Customer (kWh)					
Single-Family Heat	15,052	14,808	14,813	14,347	14,119
Single-Family Non-Heat	10,312	10,112	10,010	9,959	9,873
Multiple-Family Heat	8,302	8,220	8,090	7,890	7,804
Multiple-Family Non-Heat	6,074	6,004	5,959	5,916	5,872
Mobile Home Heat	13,993	14,028	14,167	13,622	13,497
Mobile Home Non-Heat	10,626	10,722	10,914	10,385	10,294
Other	10,561	10,703	10,828	10,500	10,472
Average Use per Customer	10,351	10,191	10,102	9,913	9,793
Ultimate Deliveries (million of kWh)					
Single-Family Heat	1,644	1,623	1,635	1,589	1,568
Single-Family Non-Heat	3,616	3,580	3,591	3,615	3,628
Multiple-Family Heat	1,484	1,487	1,491	1,487	1,499
Multiple-Family Non-Heat	350	353	355	360	367
Mobile Home Heat	425	427	432	413	407
Mobile Home Non-Heat	41	42	43	41	40
Other	52	52	53	51	51
			0	0	0
Schedule 7 Deliveries	7,613	7,563	7,600	7,556	7,560
Residential Lighting	5	3	3	3	3
Total Residential Deliveries	7,618	7,567	7,604	7,560	7,563

1/ SDEC16E

2/ weather-adjusted

Exhibit 1206: Commercial Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change (1)				
	2014 (2)	2015 (2)	2016 (2)	2017	2018	2014	2015	2016	2017	2018
Food Stores	466	456	431	426	419	2.1%	-2.0%	-5.5%	-1.1%	-1.7%
Govt. & Education	995	998	969	962	960	1.8%	0.3%	-3.0%	-0.7%	-0.1%
Health Services	731	729	721	725	726	0.3%	-0.3%	-1.2%	0.6%	0.1%
Lodging	105	105	107	104	103	-0.6%	0.8%	1.6%	-2.6%	-1.6%
Misc. Commercial	639	640	665	643	632	0.7%	0.1%	4.0%	-3.3%	-1.6%
Department Stores/Malls	351	350	343	354	353	1.1%	-0.3%	-2.1%	3.2%	-0.2%
Office & F.I.R.E. (3)	1,050	1018	993	969	957	1.7%	-3.1%	-2.5%	-2.4%	-1.2%
Other Services	803	834	863	860	855	0.3%	3.8%	3.5%	-0.3%	-0.6%
Other Trade	724	727	720	714	703	1.5%	0.5%	-1.0%	-0.8%	-1.6%
Restaurants	478	481	480	488	486	0.7%	0.5%	-0.2%	1.6%	-0.4%
Trans., Comm. & Utility	652	649	629	632	625	1.5%	-0.5%	-3.1%	0.6%	-1.2%
Total Commercial	6,994	6,988	6,920	6,878	6,819	1.2%	-0.1%	-1.0%	-0.6%	-0.9%

1/ calculated using rounded-numbers

2/ weather-adjusted

3/ Finance, Insurance, and Real Estate

Exhibit 1207: Manufacturing Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change (1)				
	2014 (2)	2015 (2)	2016 (2)	2017	2018	2014	2015	2016	2017	2018
Food & Kindred Products	236	247	257	263	264	5.4%	4.8%	3.9%	2.2%	0.5%
High Tech	2,142	2,368	2,459	2,512	2,614	10.3%	10.6%	3.8%	2.1%	4.1%
Lumber & Wood	98	95	93	97	96	-0.9%	-2.8%	-2.9%	4.5%	-0.4%
Metal Manufacturing and Fab	493	478	450	427	426	-1.5%	-2.9%	-5.9%	-5.2%	-0.1%
Other Manufacturing	750	737	712	729	729	10.1%	-1.7%	-3.4%	2.3%	0.0%
Paper & Allied Products	712	788	313	301	292	-23.1%	10.7%	-60.2%	-4.0%	-3.1%
Transportation Equipment	185	191	173	169	167	10.0%	3.5%	-9.6%	-2.4%	-0.9%
Total Manufacturing	4,616	4,907	4,458	4,497	4,589	1.7%	6.3%	-9.1%	0.9%	2.0%

1/ calculated using rounded-numbers

2/ weather-adjusted

Exhibit 1208: Forecast of Deliveries to Miscellaneous Rate Schedules

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change (1)				
	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018
Residential										
Outdoor Area Lighting (15R) (3)	5	3	3	3	3	-25.9%	-33.6%	-2.2%	1.3%	0.0%
Secondary (Commercial)										
Outdoor Area Lighting (15C) (4)	15	13	13	13	13	-7.5%	-9.0%	-1.8%	-0.7%	-0.1%
Farm Irrigation et al. (5)	80	92	80	86	87	2.5%	15.6%	-13.4%	7.3%	1.3%
Street and Other Lighting (6)	98	84	73	61	54	-9.7%	-14.2%	-13.9%	-15.8%	-12.2%
Total Miscellaneous Commercial	193	190	166	160	154	-4.9%	-1.5%	-12.8%	-3.4%	-4.0%
All Miscellaneous Schedules (7)	198	193	169	163	157	-5.6%	-2.3%	-12.6%	-3.3%	-3.9%

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

Exhibit 1209: Total Delivery and Demand Forecast

Net of Incremental Energy Efficiency (4)

	Million kWh (1)	Average MW (2)	Peak MW (3)
2009	19,165	2,337	3,949
2010	18,893	2,274	3,582
2011	19,138	2,334	3,555
2012	19,248	2,312	3,597
2013	19,265	2,346	3,869
2014	19,420	2,329	3,866
2015	19,651	2,344	3,914
2016	19,147	2,287	3,726
2017	19,094	2,320	3,594
2018	19,124	2,323	3,603

1/ cycle-month basis, at end-user meters, weather adjusted; includes actual deliveries through 2016

2/ calendar basis, at the bus bar, actual through 2016, not adjusted for weather.

3/ coincidental annual system peak at bus bar; includes actual through 2016, not adjusted for weather.

4/ 2017 and 2018 are the incremental EE adjusted forecast.

Exhibit 1210: Forecast of 2018 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	7,563	0	7,563
Secondary	6,746	521	7,266
Primary	2,785	1,103	3,888
Transmission	59	294	353
Lighting	54	0	54
Total Retail (2)	17,207	1,918	19,125

1/ Includes economic replacement VPO deliveries

2/ Schedule 485/489 deliveries.

3/ Totals may not add due to rounding.

Exhibit 1211: Trended Weather HDD and CDD Comparison

	2018 Weather Variables Based on Trended Weather Approach		2018 Weather Variables Based on 15-Year Average (2001-2015)	
Billing Month	HDD65	CDD65	HDD65	CDD65
January	750.9	0.0	767.5	0.0
February	648.5	0.0	675.1	0.0
March	567.5	0.0	584.5	0.0
April	419.7	0.0	449.2	0.1
May	282.3	5.9	307.7	5.6
June	141.3	33.6	158.4	29.8
July	46.1	117.4	45.9	106.6
August	12.8	195.3	5.2	173.2
September	22.4	170.6	18.8	144.9
October	101.9	46.1	121.4	38.3
November	331.0	1.5	351.8	1.9
December	650.3	0.0	662.0	0.0
Annual	3,974.6	570.3	4,147.7	500.5

Exhibit 1212: Trended Weather Approach Resources

Livezey, Robert E. et al. "Estimation and Extrapolation of Climate Normals and Climatic Trends." *Journal of Applied Meteorology and Climatology* , vol. 46, 2007, pp. 1759-1776, http://journals.ametsoc.org/doi/pdf/10.1175/2007JAMC1666.1. Accessed Nov. 2016.

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Wilks, Daniel S. and Robert E. Livezey. "Performance of Alternative "Normals" for Tracking Climate Changes, Using Homogenized and Nonhomogenized Seasonal U.S. Surface Temperatures." *Journal of Applied Meteorology and Climatology* , vol. 52, 2013, pp. 1677-1687, http://journals.ametsoc.org/doi/pdf/10.1175/JAMC-D-13-026.1. Accessed Nov. 2016.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Marc Cody
Robert Macfarlane

February 28, 2017

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Robert Macfarlane. I am a senior analyst in Pricing and Tariffs for PGE. I am responsible, along with Mr. Cody, for the development of the marginal cost studies.

My name is Marc Cody. I am an senior 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 studies. PGE Exhibit 1301 provides a summary of these marginal costs by component. The summary lists costs by PGE rate schedule for generation capacity and energy, subtransmission, substation, feeder backbone and tapline, transformers, service laterals, meters and customer service costs. Rate schedule changes are discussed in PGE Exhibit 1300.

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 such as distribution substations and feeders, or 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 1400.

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. What type of simple cycle combustion turbine (SCCT) did you use to estimate the marginal capacity costs?

A. Consistent with the methodology used to establish prices in UE 294, we use an "F-class" SCCT. This unit has lower capital costs than the LMS 100 and reciprocating engine units described in PGE's 2016 Integrated Resource Plan (IRP).

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" 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) To the SCCT capacity costs add 17% reserve requirements consistent with PGE's 2016 IRP.

3. Finally, express the capacity and energy values in real levelized terms.

Q. What are the sources of the overnight capital costs for the resources used in the model?

A. PGE's 2016 IRP is the source of the overnight capital costs 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 (RPS) 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 SB 1547.

Q. What is the source of your long-term gas price forecast?

A. We used the Wood Mackenzie long-term gas price forecast dated November 2016 for the Sumas and AECO hubs, blended with near term forward curves. We equally weighted the projected burnertip 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 (PTC) in your analysis?

A. Yes. The PTC is included at its full level, as available for a resource that commences construction in 2016 for a 2018 online date. This assumption is consistent with the test period for this proceeding.

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 $40.88/MWh in real levelized 2018 dollars.

Q. How did you estimate each rate schedule's long-run marginal cost of energy?

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 production cost model, MONET.

Q. Did you include an estimate of load following costs in the marginal cost of generation analysis as specified in the UE 294 Second Partial Stipulation?

A. Yes.

Q. What is your estimate of PGE's cost-of-service (COS) load following capacity requirements and how do you calculate this estimate?

A. Based on 2014 15-minute interval load research data reconciled to balancing authority loads, a load following requirement of about 240 megawatts (MWs) is estimated for COS customers. This amount of load following requirement is calculated by summing the individual COS rate schedules' 15-minute interval loads and then calculating the maximum and minimum values of these summed loads within each hourly interval. The difference between these maximum and minimum values within each hourly interval at the 99th percentile provides the 240 MW figure.

Q. How do you estimate the marginal load following costs of the 240 MW?

A. We multiply the 240 MW load following requirement by the difference in the unit marginal capacity costs of the "basic" capacity generator contained in PGE Exhibit 1301 and a rapid start LMS 100 capacity generator. The load following amount of 240 MW times the real levelized unit capacity cost difference of approximately $52/kW yields approximately $12.4 million in load following marginal costs. PGE Exhibit 1301 contains a summary of this calculation.

Q. How do you allocate the load following requirements to the individual rate schedules?

A. Each rate schedules' allocation of load following requirements is calculated in the following manner:

1) For each rate schedule calculate the difference in loads from each 15-minute interval to the next 15-minute interval.
2) For each 15-minute interval, determine if the change in each rate schedule's load is either consistent with or contrary to the sum of the rate schedules' interval changes.

3) If the rate schedule's change in load is in the same direction as the sum of the COS load changes, record the change as a positive amount. If the rate schedule's change in load is in the opposite direction of the sum of the COS interval load changes, record the amount of change as a negative number.
4) Sum the positive and negative interval entries for each rate schedule and calculate the load following percentage responsibility for each rate schedule as a percentage of the total sum of changes in COS interval loads.
5) Apply these load following percentages to the marginal cost of providing load following capacity described above.

III. Transmission Marginal Cost Study

Q. Have you performed a transmission unit marginal costs analysis for this docket?

A. Yes. Based on the two transmission projects contained in PGE Exhibit 1302 we calculate a unit marginal cost of $86.31/kW.

Q. Why have you not performed traditional marginal unit costs analyses for transmission in past dockets?

A. Generally because of its limited transmission system, PGE has not had a large amount of transmission investment. It has been more expeditious to directly allocate the relatively small transmission revenue requirement.

Q. Do the two transmission projects discussed in PGE Exhibit 1302 provide sufficient investment to perform a traditional unit marginal costs analysis?

A. Yes. The two transmission projects identified in PGE Exhibit 1302 provide sufficient investment to justify a traditional unit marginal cost analysis. Column (A) in PGE Exhibit 1301, page 3, contains the result of such an analysis.

Q. Is PGE a transmission-dependent utility?

A. Yes. PGE is a transmission-dependent utility that purchases about 3,700 MW of transmission from BPA in order to integrate its generation and purchased power. PGE operates a limited transmission system comprised of approximately 268 pole miles of 500 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.

Q. What drives additions to PGE's existing transmission system?

A. As specified in PGE Exhibit 1302[1], PGE's transmission planners evaluate whether additions to PGE's existing transmission system are needed to meet NERC and 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[2]. 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 10 months of peak loads when evaluating reliability, we extend the peak load criteria slightly to 12 months when calculating unit marginal costs. A twelve month criteria, or 12 coincident peak (12CP) is also consistent with how the Federal Energy Regulatory Commission determines PGE's Open Access Transmission Tariff prices.

Q. Has the Commission previously evaluated a PGE proposal to calculate marginal unit costs based on peak loads?

A. Yes. In UM 827, a generic marginal cost docket, the Commission evaluated PGE's calculation of unit marginal costs based on peak loads. The Commission stated the following in Order 98-374:

> We are satisfied with the transmission marginal cost analyses presented by the utilities. As PGE points out, the facilities design approach is not appropriate for calculating transmission marginal costs. Transmission planners must anticipate constant variation in peak loads. The facilities design approach is more appropriate for less dynamic functions of the system.

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[1] Portland General Electric Company's Near Term Local Transmission Plan For the 2016-2017 Planning Cycle.

[2] 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 2017-2021. 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. Then we divide the cost by the substation transformer capacity in kW, and annualize the cost per kW. Columns (B) and (C) in PGE Exhibit 1301, 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 kilovolt (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 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) and (E) on page 3 of PGE Exhibit 1301 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 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 (F) in PGE Exhibit 1301 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 (G) in PGE Exhibit 1301, 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 1301, Summary of Distribution and Customer Marginal Cost Studies, are inclusive of test-period distribution O&M.

Q. The UE 294 Second Partial Stipulation required PGE to evaluate the maintenenace costs of secondary voltage conductors and the applicability of those costs to specific rate schedules and delivery voltages. Has PGE met this requirement?

A. Yes. In consultation with field personnel, we reviewed construction estimates for underground secondary voltage conductors and service laterals. Recent marginal cost studies have assumed that pad-mounted transformers that serve multiple customers from a single transformer are configured with underground service laterals that radiate outward from the transformer, similar to spokes on a wheel. This type of configuration does not require any secondary service conductors.

PGE's current underground standards have evolved such that transformers serving multiple residential customers now incorporate secondary voltage conductors that extend to connection points for multiple service laterals.

Q. Have you incorporated this type of configuration into the current marginal cost of service study?

A. Yes, this type of configuration is incorporated into the marginal transformer and service costs for Schedule 7 residential customers.

Q. Please explain how this impacts the maintenance cost of secondary conductors.

A. PGE allocates its projected test period service and transformer maintenance costs on the basis of each schedule's marginal costs; hence changes in the Schedule 7 service and transformer marginal capital costs resulting from the incorporation of secondary conductors will result in changes in how test period service and transformer maintenance costs are allocated to the rate schedules. All else equal, the inclusion of secondary conductors for residential customers service and transformer costs will result in higher allocated test period maintenance costs to residential customers.

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 (H) on page 3 of PGE Exhibit 1301, 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 2018 test period and 2016 actual costs to develop the 2018 test year customer marginal costs (CMC). These costs are found in FERC Accounts 902, 903, 905, 908, and 909. The 2018 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 rate case – UE 294?

A. Yes, the methodology is the same. As in UE 294, 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.

Examples of Customer Marginal Cost Calculations

Q. Please provide an example of how you calculate metering marginal costs.

A. The 2018 forecasted budget amount for FERC account 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 Information System billing costs are allocated by the number of customers, except streetlights and traffic signals.
- The costs for Printing and Automated Mail Services are allocated based on the number of paper bills delivered.
- Network Data Operation 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 consumer 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 budget amount for the Special Attention Operations Department is allocated based on the number of residential customers.

- 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 (poles and luminaires) of providing lighting service using a real levelized annual revenue requirement.

Q. Please describe how you calculate the amount of outdoor lighting maintenance.

A. Similar to UE 294, 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 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 Light-Emitting Diode (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 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 1405.

VII. Qualifications

Q. Mr. Cody, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree and a Master of Science degree from Portland State University. Both degrees were in Economics. The Master of Science degree has a concentration in econometrics and industrial organization.

Since joining PGE in 1996, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on cost of capital estimation, marginal cost of service, rate spread and rate design.

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. 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. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1301	Marginal Cost Study
1302	PGE's Draft Near Term Local Transmission Plan

PORTLAND GENERAL ELECTRIC
2018 MARGINAL ENERGY COSTS

Schedule	Busbar Energy (MWh)	Marginal Energy Cost
Schedule 7	8,078,715	$280,770,904
Schedule 15	17,540	$554,684
Schedule 32	1,670,046	$57,329,403
Schedule 38	32,198	$1,135,689
Schedule 47	22,769	$773,334
Schedule 49	70,046	$2,378,448
Schedule 83	2,986,909	$102,934,054
Schedule 85	3,065,104	$104,952,514
Schedule 89	659,052	$22,231,578
Schedule 90-P	1,672,622	$56,202,387
Schedule 91/95	54,173	$1,713,113
Schedule 92	3,040	$102,189
TOTALS	18,332,214	$631,078,295

Load Following Allocation

Schedules	Load Follow Allocation	Allocation
Schedule 7	$8,937,442	71.96%
Schedule 15	($16,694)	-0.13%
Schedule 32	$782,113	6.30%
Schedule 38	$22,709	0.18%
Schedule 47	$10,270	0.08%
Schedule 49	$27,510	0.22%
Schedule 83	$1,360,621	10.96%
Schedule 85	$1,245,252	10.03%
Schedule 89	$93,587	0.75%
Schedule 90	$8,851	0.07%
Schedule 91/95	($51,558)	-0.42%
Schedule 92	($104)	0.00%
TOTAL	$12,420,000	100.00%
LF Marginal Costs ($000)	$12,420,000	

Load Following Requirements (MW)	240
Cost of Flexible Capacity ($/kW)	$157.07
Cost of Conventional Capacity	$105.32
Delta Capacity Cost	$51.75
Load Following Marginal Costs	$12,420,000

PORTLAND GENERAL ELECTRIC
2018 MARGINAL ENERGY AND CAPACITY COSTS

Year	Thermal Capacity SCCT $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2018	105.32	30.82	40.88	15.00%	105.32	32.33
2019	107.43	31.43	41.70	15.00%	107.43	32.97
2020	109.58	32.06	42.53	20.00%	109.58	34.16
2021	111.77	32.70	43.38	20.00%	111.77	34.84
2022	114.00	33.36	44.25	20.00%	114.00	35.54
2023	116.28	34.02	45.14	20.00%	116.28	36.25
2024	118.61	34.71	46.04	20.00%	118.61	36.97
2025	120.98	35.40	46.96	27.00%	120.98	38.52
2026	123.40	36.11	47.90	27.00%	123.40	39.29
2027	125.87	36.83	48.86	27.00%	125.87	40.08
2028	128.38	37.57	49.83	27.00%	128.38	40.88
2029	130.95	38.32	50.83	27.00%	130.95	41.70
2030	133.57	39.08	51.85	35.00%	133.57	43.55
2031	136.24	39.87	52.88	35.00%	136.24	44.42
2032	138.97	40.66	53.94	35.00%	138.97	45.31
2033	141.75	41.48	55.02	35.00%	141.75	46.22
2034	144.58	42.31	56.12	35.00%	144.58	47.14
2035	147.47	43.15	57.24	45.00%	147.47	49.49
2036	150.42	44.01	58.39	45.00%	150.42	50.48
2037	153.43	44.90	59.56	45.00%	153.43	51.49
Real Levelized	$105.32	$30.82	$40.88		$105.32	$33.50
NPV	$1,388	$406	$539		$1,388	$442
Nominal Levelized	$123.05	$36.00	$47.76		$123.05	$39.14
Real Levelized	$105.32	$30.82	$40.88		$105.32	$33.50

Composite Income Tax Rate			39.94%
Property Tax Rate			1.50%
Inflation Rate			1.84%
Capitalization:			
Preferred	0.00%	0.00%	0.00%
Common	50.00%	9.60%	4.80%
All Equity	50.00%		4.80%
Debt	50.00%	5.77%	2.89%
Cost of Capital			7.69%
After-Tax Nominal Cost of Capital			6.53%
After-Tax Real Cost of Capital			4.61%

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 ($/kW)	TRANSFORMER & SERVICE COSTS ($/Customer)	METER COSTS ($/Customer)	CUSTOMER COSTS ($/Customer)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Schedule 7 Residential								
Single-phase	$86.31	$12.94	$12.41	$24.36	$16.02	$75.35	$20.73	$59.16
Three-phase	$86.31	$12.94	$12.41	$24.36	$16.02	$128.27	$62.80	$59.16
Schedule 15 Residential	$86.31	$12.94	$12.41	$25.56	$18.16	$2.67	N/A	$12.53
Schedule 15 Commercial	$86.31	$12.94	$12.41	$25.56	$18.16	$2.67	N/A	$14.18
Schedule 32 General Service								
Single-phase	$86.31	$12.94	$12.41	$30.20	$23.78	$137.97	$18.32	$58.81
Three-phase	$86.31	$12.94	$12.41	$30.20	$10.43	$205.49	$78.49	$58.81
Schedule 38 TOU								
Single-phase	$86.31	$12.94	$12.41	$30.17	$22.13	$179.91	$62.80	$134.96
Three-phase	$86.31	$12.94	$12.41	$30.17	$10.60	$531.34	$140.82	$134.96
Schedule 47 Irrigation								
Single-phase	$86.31	$12.94	$12.41	$30.20	$23.78	$9.79	$62.43	$56.61
Three-phase	$86.31	$12.94	$12.41	$30.20	$10.43	$19.47	$93.35	$56.61
Schedule 49 Irrigation								
Single-phase	$86.31	$12.94	$12.41	$30.17	$22.13	$131.88	$62.80	$105.66
Three-phase	$86.31	$12.94	$12.41	$30.17	$10.60	$131.88	$77.06	$105.66
Schedule 83 Secondary General Service								
Single-phase	$86.31	$12.94	$12.41	$30.17	$22.13	$356.24	$62.43	$204.99
Three-phase	$86.31	$12.94	$12.41	$30.17	$10.60	$881.44	$139.36	$204.99
Schedule 85 Secondary General Service	$86.31	$12.94	$12.41	$22.40	$7.59	$2,057.03	$175.18	$1,212.63
Schedule 85 Primary General Service	$86.31	$12.94	$12.41	$22.40	$7.59	$0.00	$1,971.73	$1,212.63
Schedule 89 Secondary	$86.31	$12.94	$12.41	$86,625 ($/Customer)	N/A	$13,724.84	$190.01	$8,675.03
Schedule 89 Primary	$86.31	$12.94	$12.41	$86,625 ($/Customer)	N/A	$0.00	$1,975.66	$8,675.03
Schedule 89 Subtransmission	$86.31	$12.94	N/A	$83,765 ($/Customer)	N/A	N/A	$19,913.86	$8,675.03
Schedule 90 Primary	$86.31	$12.94	$12.41	$282,102	NA	$0.00	$1,971.73	$27,734.36
Schedules 91 & 95 Streetlighting	$86.31	$12.94	$12.41	$25.56	$18.16	$2.67	N/A	$943.98
Schedules 92 Traffic Signals	$86.31	$12.94	$12.41	$25.56	$9.17	$8.79	N/A	$941.76

Portland General Electric Company's Near Term Local Transmission Plan For the 2016-2017 Planning Cycle

Contents

1. Introduction

This 2016 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. This Near Term Plan constitutes PGE's complete "expansion plan of the Transmission Provider" as described in Section 12.2.3 of Attachment O to our 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 five (5) 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 the Northern Tier Transmission Group (NTTG) and the Western Electric Coordinating Council (WECC). PGE uses the NTTG 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 the NTTG's website at www.nttg.biz.

2. Planning Process and Timeline

This plan is for the 2016-2017 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	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	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. Figure 2 shows the meetings held in 2016 and the meetings scheduled for 2017.

Figure 2: Quarterly Customer Meetings

Planning Cycle Quarter	Meeting Date
1	March 8, 2016
2	June 7, 2015
3	September 29, 2016
4	*December 6, 2016*
5	*March 7, 2017*
6	*June 6, 2017*
7	*September 5, 2017*
8	*December 5, 2017*

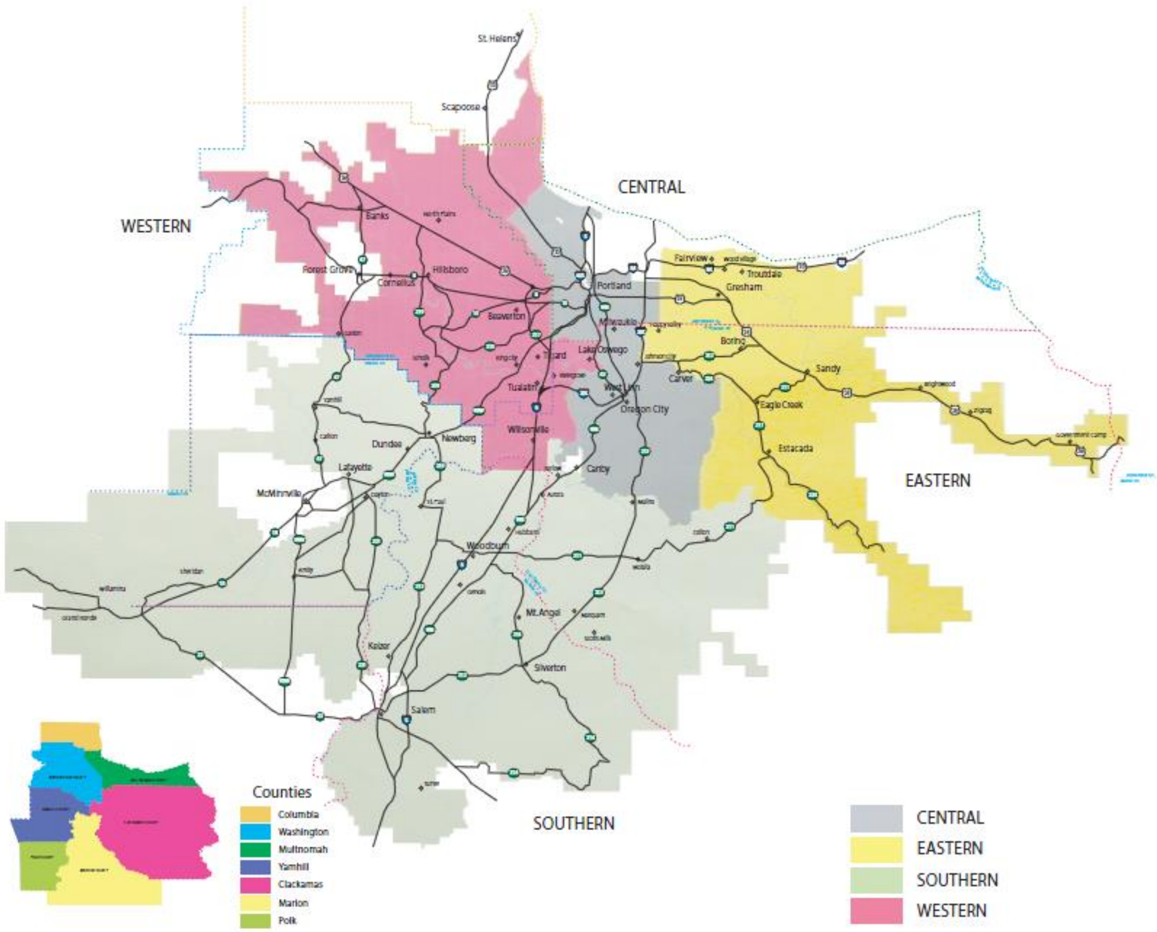
***Meeting dates in *italics* are upcoming and subject to change.**

3. Transmission System Plan Inputs and Components

3.1. PGE's Transmission System

Portland General Electric's (PGE) service territory covers more than 4,000 square miles and provides service to over 825,000 customers. PGE's service territory is confined within Multnomah, Washington, Clackamas, Yamhill, Marion, and Polk counties in northwest Oregon, as shown in Figure 3.

Figure 3: Map of PGE's Service Territory



PGE's Transmission System is designed to reliably distribute power throughout the Portland & Salem regions for the purpose of serving native load. In addition to the load-service transmission facilities, PGE also maintains ownership of networked Transmission System circuits (See Figure 4) used to integrate transmission and generation resources on the Bulk Electric System.

Figure 4: PGE-Owned Transmission System Circuits

Transmission Circuit	Circuit Miles	Transmission Path
Grizzly-Malin 500kV	178.5 miles	COI[1]
Grizzly-Round Butte 500kV	15.6 miles	
Colstrip-Townsend #1 500kV	37.3 miles (15% ownership)	
Colstrip-Townsend #2 500kV	36.9 miles (15% ownership)	
Bethel-Round Butte 230kV	99.2 miles	WOCS[2]
St Marys-Trojan 230kV	41.4 miles	SOA[3]
Rivergate-Trojan 230kV	35.1 miles	SOA

In total, PGE owns 1,583 circuit miles of sub-transmission/transmission at voltages ranging from 57kV to 500kV. (See Figure 5)

Figure 5: PGE Circuit Miles Owned (By Voltage Level)

Voltage Level	Pole Miles	Circuit Miles
500 kV	268	268
230 kV	270	319
115 kV	494	556
57 kV	418	439

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 Peak Reliability Seasonal System Operating Limits Coordination Process, Appendix 'V'.

[1] California-Oregon Intertie
[2] West of Cascades South
[3] South of Allston

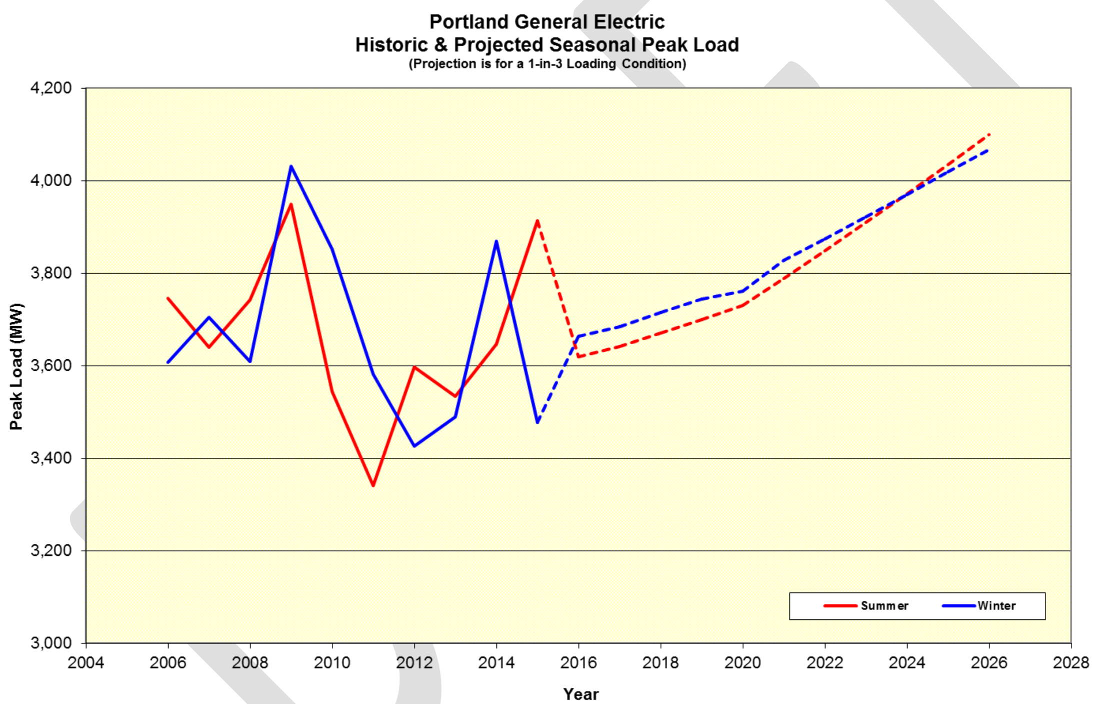
Figure 6: Summer/Winter Loading Conditions and Corresponding Daily-Averaged Temperatures

Summer	
1-in-2	79ºF
1-in-3	81ºF
1-in-5	83ºF
1-in-10	85ºF
1-in-20	87ºF

Winter	
1-in-2	28ºF
1-in-3	24ºF
1-in-5	21ºF
1-in-10	18ºF
1-in-20	15ºF

Figure 7: Portland General Electric's Historic & Projected Seasonal Peak Load

(Projection is for a 1-in-3 Loading Condition)



As depicted in Figure 7, PGE's all-time peak load occurred on December 21, 1998, with the Net System Load[4] reaching 4073 MW. PGE's all time summer peak occurred on July 29, 2009 with the Net System Load reaching 3949 MW.

[4] 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 2016-2017 planning cycle.

3.5 Stakeholder Submissions

Any stakeholder may submit data to be evaluated as part of the preparation of the draft Longer 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 2016-2017 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 forecasted system demands. Studies are performed annually to evaluate where transmission upgrades may be needed to meet performance requirements.

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-010-0 and MOD-012-0 reliability standards. 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 115kV transmission system (primarily auto mode - time-clock; two auto mode - voltage control) and on the 57kV transmission system (auto mode - voltage control).

Studies are evaluated for the Near Term Planning Horizon (years 1 through 5) and the Longer Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE's transmission system. The load model used in the studies is obtained from PGE's corporate forecast, reflecting a 1-in-3 demand level for peak summer and peak winter conditions. Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models. Transmission equipment is assumed to be out of service in the 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 one of the five years

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 system 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 8: Powerflow Base Cases Used in 2016 Assessment

		Study Year	Origin WECC Base Case	PGE Case Name	PGE System Load (MW)
	Year One/Two Case	2018	2015 HS4-OP	18 HS PLANNING	3759
	Year Five Case	2021	2020 HS2	21 HS PLANNING	3852
SUMMER	Year One/Two Sensitivity	2018	2015 HS4-OP	18 HS SENSITIVITY	3808
	Year Five Sensitivity	2021	2020 HS2	21 HS SENSITIVITY	3895
	Long Term Case	2026	2024 HS1	26 HS PLANNING	4468
	Year One/Two Case	2017-18	2014-15 HW3-OP	17-18 HW PLANNING	3798
	Year Five Case	2021-22	2019-20 HW1	21-22 HW PLANNING	3867
WINTER	Year One/Two Sensitivity	2017-18	2014-15 HW3-OP	17-18 HW SENSITIVITY	3920
	Year Five Sensitivity	2021-22	2019-20 HW1	21-22 HW SENSITIVITY	4019
	Long Term Case	2026-27	2023-24 HW1	26-25 HW PLANNING	4066
SPRING	Near Term Off Peak Case	2018	2017 LSP1-S	18 LSP PLANNING	2427
	Near Term Off Peak Sensitivity	2018	2017 LSP1-S	18 LSP SENSITIVITY	2427

The Bulk Electric System is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-4 reliability standard. When system simulations indicate an inability of the systems to respond as prescribed in the NERC TPL-001-4 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Planning Horizon.

4.1. Steady State Studies

PGE performs steady-state studies for the Near-Term and Long-Term Transmission Planning Horizons. The studies consider all contingency scenarios identified in Table 1 of the NERC TPL-001-4 reliability standard to determine if the Transmission System meets performance requirements. These studies also assess the impact of Extreme Events on the system expected to produce severe system impacts.

The contingency analyses simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent tripping of generators due to voltage limitations and tripping of transmission elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

Capacity addition projects are developed when simulations indicate the system's inability to meet the steady-state performance requirements for 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. Transient Stability Studies

PGE evaluates the voltage and transient stability performance of the Transmission System for contingencies to PGE and adjacent utility equipment at 500kV and 230kV. 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 500kV and 230kV 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 500kV and 230kV facilities; and the majority of 115kV 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 against the performance requirements outlined in the NERC TPL-001-4 reliability standard and against the WECC Disturbance-Performance Table of Allowable Effects on Other Systems (Table I). The simulation durations are run to 20 seconds.

Figure 9: WECC Disturbance-Performance Table of Allowable Effects on Other Systems[5]

WECC and NERC Categories	Outage Frequency Associated with the Performance Category	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard
A (P0)	Not Applicable	Nothing in addition to NERC		
B (P1)	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6 Hz** for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C (P2-P7)	0.033-0.33	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.	Not below **59.0 Hz** for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D (Extreme)	< 0.033	Nothing in addition to NERC		

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.

5 The WECC TPL-001-WECC-CRT Regional Criterion is currently undergoing a revision to adapt the new categories (P0-P7) in the NERC TPL-001-4 reliability standard.

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

There are no contingency loading or voltage concerns on PGE's system in the Near Term Planning Horizon for NERC TPL-001-4 Categories P1, P2, P3, P4, and P5. NERC TPL-001-4 Category P6 and P7 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 Transient Stability

The Near Term transient stability studies indicate that PGE's Transmission System exhibits adequate transient stability throughout the 500kV and 230kV transmission systems. The minimum transient frequency response recorded did not dip below 59.6 Hz for any of the contingency events studied on PGE's Transmission 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 Transmission System.

5.3. Projects Currently Included in the Near Term Plan

There are four projects planned for implementation in the Near Term Planning Horizon. The four projects are described in detail in Appendix A.

Appendix A: 5 Year Project List

Potential projects currently included in the Longer Term Plan are:

- Blue Lake-Gresham 230kV Upgrade
- Horizon Phase II
- Harborton Reliability Project
- Marquam Substation

These projects are described in more detail on the following pages.

Blue Lake-Gresham 230kV Upgrade

- **Project Purpose**
  - Maintain compliance with NERC Reliability Standards in the Near Tern Planning Horizon.

    The Near Term studies indicate that the loss of the Linneman-Troutdale BPA 230kV circuit may cause the Gresham-Troutdale BPA 230kV circuit to approach its summer emergency rating during peak summer conditions. Conversely, the loss of the Gresham-Troutdale BPA 230kV circuit may cause the Linneman-Troutdale BPA 230kV circuit to approach its summer emergency rating during peak summer conditions.

    In addition, the loss of the Gresham-Troutdale 230kV circuit and Linneman-Troutdale BPA 230kV circuit common tower line may cause the Blue Lake VWR2 transformer to approach its summer emergency rating during peak summer conditions. The loss of the west bus at BPA's Troutdale substation or a breaker failure to the Troutdale PGA A1306 breaker may cause the Linneman-Troutdale 230kV circuit to approach its summer emergency rating during peak summer conditions.

- **Project Scope**
  - Construct a new Blue Lake -Gresham 230kV circuit (approximately 6 miles).
  - Reconductor the existing Blue Lake-Troutdale 230kV circuit and rebuild the line to accommodate the construction of a new Blue Lake-Troutdale BPA #2 230kV circuit (approximately 1.5 miles)
  - Rebuild the Blue Lake substation 230kV yard to a six position ring bus.
  - Install a new 230kV breaker position at Gresham substation to accommodate the new Blue Lake circuit and replace overdutied and antiquated equipment at Gresham substation.
  - Install a new 230kV breaker position at BPA's Troutdale substation to accommodate the new Blue Lake-Troutdale BPA #2 230kV circuit

- **Project Status**
  - Under Construction

- **Project Requirement Date**
  - The project is currently projected for completion in 2017.

Horizon Phase II

- **Project Purpose**
    - Maintain compliance with the NERC Reliability Standards in the Near Term Planning Horizon

      The Near Term studies indicate that the Horizon VWR1 bulk power transformer my approach its summer normal rating during peak summer loading conditions. In addition, the loss of a 500kV or 230kV circuit at BPA's Keeler substation may cause the Horizon VWR1 transformer to approach its summer emergency rating.

      In addition, the loss of the Horizon-Keeler BPA 230kV circuit in conjunction with the loss of a bulk power transformer or 115kV circuit at St Marys substation my result in loading concerns on PGE's underlying 115kV system.

- **Project Scope**
    - Install a second bulk power transformer at Horizon substation.
    - Construct a new 230kV circuit between Horizon substation and the Springville Junction (approximately 4.4 miles). Tie into the existing St Marys-Trojan 230kV circuit to create a Horizon-St Marys-Trojan 230kV circuit.
    - Replace the underrated substation equipment at Sunset substation.

- **Project Status**
    - The project is under construction

- **Project Requirement Date**
    - The project is currently projected for completion in 2017.

Harborton Reliability Project

- **Project Purpose**
    - Address transmission operations flexibility for the loss of the Rivergate bulk power transformer.
    - PGE plans to reconstruct the Harborton substation with a new 115kV yard and add a new 230kV yard. The 230kV sources will be provided by looping in the existing Trojan-Rivergate 230kV line, and the Horizon-Trojan-St Marys 230kV line (see the Horizon Phase II project). The new Harborton bulk power transformer will provide a strong source to improve voltage and power flow performance of the Northwest Portland 115kV system.
    -
- **Project Scope**
    - Rebuild the Harborton 115kV yard to a breaker and one half configuration.
    - Build a new 230kV breaker and one half yard at Harborton substation.
    - Route five 230kV lines to Harborton.
    - Install a new bulk power transformer at Harborton.
    - Reconductor the 115kV lines from Harborton substation to Canyon substation.
    - Reconfigure the 115kV system to provide a source to Northwest Portland from Harborton substation.
- **Project Status**
    - Under Construction
- **Project Requirement Date**
    - The project is currently projected for completion in 2020.

Marquam Substation

- **Project Purpose**
    - Maintain compliance with NERC Reliability Standards in the Near Term Planning Horizon.

      PGE plans to energize the Marquam substation in downtown Portland to provide distribution service to the core area network. As a high reliability substation, Marquam will require three transmission sources at 115kV. Two transmission sources will be provided by looking in the existing Lincoln PACW-Urban 115kV line; however, a third source will need to be constructed from PGE's Harrison substation.

- **Project Scope**
    - Rebuild PGE's Harrison 115kV substation to a six position ring bus.
    - Construct the 115kV Marquam substation and loop in the Lincoln-Urban 115kv line.
    - Construct a new 115kV transmission line between Harrison and Marquam substations.

- **Project Status**
    - Under Construction

- **Project Requirement Date**
    - The project is currently projected for completion in 2018.

UE 319 / PGE / 1400
Cody – Macfarlane

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Marc Cody
Robert Macfarlane

February 28, 2017

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. Our names are Marc Cody and Robert Macfarlane. We are both Senior Analysts in Pricing and Tariffs for PGE. Our qualifications are described in PGE Exhibit 1300.

Q. What is the purpose of your testimony?

A. Our testimony and accompanying exhibits demonstrate how the proposed E-18 Tariff changes recover Portland General Electric's (PGE) 2018 revenue requirement in a way that achieves fair, just, and reasonable prices for all our customers. In addition to estimating the overall effect on customer bills, our testimony also describes the revenue requirement allocation process (ratespread), and the rate design. We also discuss the price changes to various supplemental schedules. Included in these supplemental schedules are Schedule 122 Renewable Resources Automatic Adjustment Clause, Schedule 123 Decoupling Adjustment, Schedule 143 Spent Fuel Adjustment, and Schedule 146 Colstrip Power Plant Operating Life Adjustment.

Q. Please summarize the projected Cost of Service (COS) rate impacts resulting from the proposed allocations.

A. Table 1 below summarizes the base rate impacts for the major rate schedules and the overall impact. PGE Exhibit 1402 contains more detailed information on the rate impacts for the individual schedules. Table 1 of PGE Exhibit 1402 contains the base rate impacts of the proposed prices effective January 1, 2018. The detailed bill impacts starting on page 2 of PGE Exhibit 1402 relate to prices effective January 1, 2018, 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 146

Schedule	**Jan. 1, 2018**
Schedule 7 Residential	7.1%
Schedule 32 Small Nonresidential	5.7%
Schedule 83 31-200 kW	4.2%
Schedule 85 201-4,000 kW	3.5%
Schedule 89 Over 4,000 kW	1.2%
Schedule 90 100 MWa	1.2%
COS & DA Overall	5.6%

II. Ratespread

Q. Please summarize the changes in ratespread, rate design, and tariff language you propose to make relative to PGE's last general rate case, Docket No. UE 294.

A. The key changes we propose are listed below (and explained later in testimony):

- Consistent with the UE 294 Second Partial Stipulation, we incorporate an estimate of load following marginal costs as specified in PGE Exhibit 1300 for allocating generation revenue requirements. This replaces the prior method of crediting Schedule 90 for load following and charging other rate schedules.
- Allocate the transmission revenue requirement based on the 12 coincident peak (12 CP) marginal costs specified in PGE Exhibit 1300 rather than on the basis of 75% capacity, 25% energy as stipulated in UE 294.

Q. Do you propose changes other than prices to existing supplemental schedules?

A. No.

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 guide 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 1300.

Q. How do you calculate and allocate the 2018 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 1300 by the projected 2018 COS test-period 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 schedule's relative contribution to the monthly peak hours contained in the months of January, July, August, and December (4-coincident peak or 4-CP).

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 the 2016 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 36.4% of the marginal cost of generation, and energy approximately 63.6%. These figures reflect the inclusion of load following costs as a capacity cost. The corresponding figures from UE 294 were approximately 32.8% and 67.2%.

Q. How do you allocate the transmission revenue requirements?

A. As stated above, we allocate the transmission revenue requirements on the basis of each rate schedule's 12 monthly coincident peaks (12 CP) times the unit marginal transmission costs presented in PGE Exhibit 1300.

Q. How has PGE allocated the transmission revenue requirement in past rate cases?

A. In dockets UE 115, UE 180, and UE 197, PGE allocated the transmission revenue requirement on the basis of each schedule's 12 CP. In UE 215, PGE proposed a joint capacity/energy split based on the then-proposed Cascade Crossing transmission project, which among other functions, would have supplanted some BPA transmission that was allocated on the basis of generation costs. Because Cascade Crossing was canceled, in PGE's subsequent general rate case, UE 262, PGE proposed a transmission revenue requirement allocation based on a 4 CP allocator. In settlement, parties agreed to a capacity/energy split of 65% capacity (4 CP) and 35% energy. To minimize areas of disagreement, PGE carried forward the UE 262 settlement methodology for both transmission and generation allocations in UE 283. In UE 294, PGE proposed to allocate the transmission revenue requirement on a 12 CP basis. In settlement, parties agreed to a capacity/energy split of 75% capacity (4 CP) and 25% energy.

Q. Parties to recent past 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 to <u>generation</u> the generation lead transmission lines such as the Colstrip transmission facilities and the Port Westward to Trojan lines. Hence, 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 of approximately $79 million from purchasing BPA transmission is functionalized to generation and allocated on the basis of energy and capacity in proportion to how the generation revenue requirement is allocated.

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 made 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 both of its coal plants, Boardman and 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 generation revenue requirements. As a result of this functionalization, approximately 64% of the transmission used to bring Boardman, 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 Long-Term Transition Adjustment on an energy basis to all schedules. This allocation is consistent with the Partial Stipulation in UE 262. Finally, we allocate uncollectible expense based on historical incidence for the years 2012-2016. All allocations are presented in PGE Exhibit 1404.

Q. Please describe how you allocate and price the recovery of the franchise fee revenue requirements consistent with OPUC Order No. 12-500.

A. We allocate the franchise fee revenue requirements in the same manner as in UE 294 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 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 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 requirements?

A. Yes, we make several changes from the initial allocation of revenue requirements. 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 requirements, 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. In addition because Schedule 89 would otherwise receive a base rate increase far below that of the other major rate schedules, we propose a CIO surcharge such that the Schedule 89 base rate impact is approximately equal to the rate impact of the next lowest impacted rate schedule, Schedule 90.

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; although 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 costs categories such as generation and customer service because these categories have their unique costs attributions that yield reasonable prices.

III. 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.

Schedule 32, Small Nonresidential Standard Service (30 kilowatts (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), applies to 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 100 MWa) applies to customers whose Facility Capacity exceeds 4,000 kW and whose energy consumption exceeds 100 MWa. The rate design is similar to Schedule 89, but with higher customer charges.

Q. What principles do you consider in developing the proposed prices?

A. We consider the following Bonbright[1] principles in both the cost allocation and pricing processes. The proposed prices should accomplish the following:

1) Recover the total revenue requirement;
2) Provide revenue stability and predictability to the utility;
3) Provide rate stability and predictability to customers;
4) Reflect the cost of providing service to the customer classes;
5) Be fair to the customer classes;
6) Send appropriate price signals; and
7) Be simple and understandable.

[1] "Principles of Public Utility Rates," by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, 2nd Edition, 1988.

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 1403, Rate Design, provides additional detail regarding how the individual prices for each schedule were designed.

Q. Please list the individual monthly prices for Schedule 7, Residential Service.

A. The prices are summarized below:

Table 2
Schedule 7
Residential Service Proposed Prices

Category	**Prices**
Basic Charge	$11.50 per customer per month
Transmission & Related Service Charge	2.20 mills per kWh
Distribution Charge	45.30 mills per kWh
Energy Charge First 1,000 kWh	67.95 mills per kWh
Energy Charge Over 1,000 kWh	75.17 mills per kWh

Q. Please explain how you develop these prices.

A. Although the embedded customer costs suggest a **Basic Charge** of approximately $23, we propose to increase the Basic Charge by $1.00 monthly to $11.50 in order to better match prices to embedded costs, consistent with the principles discussed above.

We develop the **Transmission & Related Service Charge** directly from the allocated transmission and ancillary services revenue requirement.

We calculate the **Distribution Charge** of 45.30 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 with a price differential of 7.22 mills per kWh.

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 customers in a manner that presumes their load shape is the same as the overall rate schedule, PGE will incur a revenue shortfall of approximately $156,000. We incorporate this impact in the standard Schedule 7 energy charge.

Q. Please list the individual monthly prices for Schedule 32, Small Nonresidential Service.

A. The prices are summarized below:

Table 3
Schedule 32
Small Nonresidential Service

Category	**Prices**
Basic Charge Single Phase	$18.00 per customer per month
Basic Charge Three Phase	$24.00 per customer per month
Transmission & Related Services Charge	1.85 mills per kWh
Distribution Charge First 5,000 kWh	45.22 mills per kWh
Distribution Charge Over 5,000 kWh	9.47 mills per kWh
Energy Charge	61.95 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 actually 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. To better reflect costs, we increase the Basic Charge for single- and three-phase service to $18.00 and $24.00 per month from their current levels of $16.00 and $22.00 respectively. These basic charges are still considerably below the embedded customer-related costs of approximately $31 and $46. 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 7 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 customers in a manner that presumes their load shape is the same as the overall rate schedule, PGE will incur a revenue shortfall of approximately $69,000. 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 Energy Service Supplier (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 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 in order 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 presumably more able to react to pricing signals triggered by their peak consumption. Schedule 83 is for secondary delivery voltage only. The proposed prices are below:

Table 4

Schedule 83
General Service 31-200 kW

Category	Monthly Prices	
Basic Charge Single Phase	$30.00	per customer per month
Basic Charge Three Phase	$40.00	per customer per month
Trans. & Related Services	$0.70	per on-peak kW
Facility Capacity Charge (First 30 kW)	$3.84	per kW Facility Capacity
Facility Capacity Charge (Over 30 kW)	$3.74	per kW Facility Capacity
Distribution Demand Charge	$2.84	per on-peak kW
COS Energy Charge On-peak	66.18	mills per kWh
COS Energy Charge Off-peak	51.18	mills per kWh
System Usage Charge	6.90	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 $30.00 and the three-phase charge of $40.00. 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 $0.70 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 $2.84 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 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 ratespread, paying particular attention to appropriately pricing the cost differentials between secondary and primary delivery voltages. The prices differentiated by delivery voltage are in Table 5 below:

Table 5
Schedule 85 General Service 201-4,000 kW

Category	Secondary Prices		Primary Prices	
Basic Charge	$530.00	per customer per month	$490.00	per customer per month
Trans. & Related Services	$0.70	per on-peak kW	$0.68	per on-peak kW
Facility Capacity Charge (First 200 kW)	$3.50	per kW Facility Capacity	$3.42	per kW Facility Capacity
Facility Capacity Charge (Over 200 kW)	$2.60	per kW Facility Capacity	$2.52	per kW Facility Capacity
Distribution Demand Charge	$2.84	per on-peak kW	$2.76	per on-peak kW
COS Energy Charge On-peak	64.41	mills per kWh	63.32	mills per kWh
COS Energy Charge Off-peak	49.41	mills per kWh	48.32	mills per kWh
System Usage Charge	1.51	mills per kWh	1.46	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 $530 and $490 respectively. These Basic Charges, subject to rounding, recover the full amount of the allocated customer-related costs. 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 $0.70 per kW of on-peak demand for secondary service, and to $0.68 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 $2.84 and $2.76 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 Customer Impact Offset (CIO). We also use this charge for Schedules 83, 85, 89, and 90 to capture the Schedule 129 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 testimony.

We calculate the COS energy charges based on the results of the generation allocations. We maintain the on- and off-peak differential at 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 6 below:

Table 6
Schedule 89 General Service Greater than 4,000 kW

Category	Secondary Prices	Primary Prices	Subtransmission Prices
Basic Charge	$3,350.00 per month	$1,910.00 per month	$4,080.00 per month
Transmission & Related Charge	$ 0.70 per on-peak kW	$0.68 per on-peak kW	$0.67 per on-peak kW
Facility Capacity Charge First 4,000 kW	$1.65 per kW Facility Capacity	$1.61 per kW Facility Capacity	$1.61 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.34 per kW Facility Capacity	$1.30 per kW Facility Capacity	$1.30 per kW Facility Capacity
Distribution Demand Charge	$2.84 per on-peak kW	$2.76 per on-peak kW	$1.36 per on-peak kW
COS Energy Charge On-peak	61.55 mills per kWh	60.54 mills per kWh	59.79 mills per kWh
COS Energy Charge Off-peak	46.55 mills per kWh	45.54 mills per kWh	44.79 mills per kWh
System Usage Charge	2.32 mills per kWh	2.28 mills per kW	2.25 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 100 average megawatts (MWa). All four of the accounts on Schedule 90 are served at primary delivery voltage; the prices are listed in Table 7 below:

Table 7
Schedule 90 General Service Greater than 4,000 kW aggregating to 100 MWa

Category	**Primary Voltage Prices**
Basic Charge	$5,600.00 per month
Transmission & Related Charge	$0.68 per on-peak kW
Facility Capacity Charge First 4,000 kW	$1.48 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.17 per kW Facility Capacity
Distribution Demand Charge	$2.76 per on-peak kW
COS Energy Charge On-peak	59.96 mills per kWh
COS Energy Charge Off-peak	44.96 mills per kWh
System Usage Charge	1.00 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 $2.76 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 the current monthly $25 Basic Charge 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.

Schedules 47 and 49, Irrigation and Drainage Pumping retain their customer charges of $35.00 and $40.00 respectively. These customer charges are 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.

Both Schedules 38 and 49 have direct access equivalent schedules; Schedules 538 and 549 respectively. The direct access equivalent schedule for Schedule 47 is Schedule 532.

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 1406.

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 schedule?

A. 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. In addition, because Schedule 89 is projected to receive a base rate increase far below the average of the other major rate schedules, through the CIO, we transfer approximately $2 million from Schedule 89/489 to Schedule 7 so that the Schedule 89 January base rate price impacts are similar to those of Schedule 90. We designate Schedule 7 as the recipient of the CIO because the proposed percentage price increase for this schedule is the largest relative to the other major rate schedules. For optional rate schedules such as Schedules 38, 47, and 49 we propose no price impact mitigation.

Q. Given that you propose to increase the Schedule 489 distribution prices, why do you make the CIO surcharge applicable to Schedule 489 as well as to Schedule 89?

A. Because if we applied the CIO surcharge to Schedule 89 and not to Schedule 489, we would create an inappropriate incentive for current Schedule 89 customers to choose long-term direct access through Schedule 489 and avoid the surcharge. Furthermore, PGE's distribution charges are generally a relatively small portion of either a Schedule 89 or Schedule 489 customer's electric energy costs. Hence the proposal to apply a CIO surcharge to Schedule 489. PGE will reevaluate its CIO proposal should PGE's revenue requirement change during this proceeding, for example due to changes in power costs resulting from updates.

Q. How do you implement the CIO?

A. We increase the System usage Charges for Schedule 89/489/589 and reduce the distribution charge for Schedule 7. For Schedule 15, we increase the distribution charge while reducing the distribution charges for Schedules 91 and 95.

IV. Other Rate Schedule Changes

Q. What changes in Schedule 123 prices do you presume for 2018?

A. For the Sales Normalization Adjustment portion of Schedule 123, we provide a preliminary estimate of the Schedule 123 prices that include activity through January 2017. For Schedule 7, the small anticipated credit in Schedule 123 will result in an increase in revenues from the current Schedule 123 credit designed to refund approximately $8 million to Schedule 7 customers during 2017. For Schedule 32, we also anticipate a credit, but again, at a lower level than current prices. We presume that the Lost Revenue Recovery Adjustment portion of Schedule 123 will be at the same level as current. The estimated change in Schedule 123 prices results in an increase in revenues of approximately $8.1 million.

Q. What 2018 changes do you propose for Schedules 122, 143, and 146?

A. We propose to set the prices for Schedules 122 and 146 to zero effective January 1, 2018. For Schedule 143, we anticipate amortizing approximately $2 million in credits we expect to receive from the Department of Energy in 2018. This results in an increase in revenues of approximately $15.5 million relative to the current amount of credits being amortized. The costs for both Schedules 122 Renewable Resources Automatic Adjustment Clause and 146 Colstrip Power Plant Operating Life Adjustment are incorporated into base rates, hence our proposal to set the prices for these schedules to zero. Schedule 122 would otherwise recover approximately $600,000 while Schedule 146 would otherwise recover approximately $5.6 million.

Q. How will the changes in the supplemental schedules above be implemented?

A. The price changes for Schedules 123 and 143 will be implemented through Advice Filings, made in October or November 2017. The price changes for Schedules 122 and 146 will be included in PGE's Compliance Filing to this docket.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1401	Proposed Tariff Changes
1402	Estimated Impact of Proposed Changes on Customers
1403	Rate Design
1404	Allocation of Costs to Customer Classes
1405	Streetlight and Area Lights

SCHEDULE 6 (Continued)

APPLICABLE

Subject to selection by the Company, eligible Residential (Schedule 7) Customers may elect to participate in the pilot as described in the Enrollment section of this tariff. The Company will select the pricing option under Monthly Rate. Eligible Customers must have a Network Meter. See the Special Conditions section for a list of relevant eligibility criteria. Customers participating in the pricing pilot will be transferred from Schedule 7 to Schedule 6 for the duration of the pilot.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)* will apply to Customers participating in the pricing pilot:

Basic Charge	$11.50		(I)
Transmission and Related Services Charge	0.220	¢ per kWh	(R)
Distribution Charge	4.530	¢ per kWh	(I)
Energy Charge			

See options that follow. The Company will choose the energy price option for each Customer.

* See Schedule 100 for applicable adjustments.

SCHEDULE 6 (Continued)

MONTHLY RATE (Continued)

Standard Block with PTR

Energy Charge

First 1,000 kWh	6.795	¢ per kWh	(R)
Over 1,000 kWh	7.517	¢ per kWh	(R)

Peak Time Rebate* (when called)
Credit at one of the following rates**:

High	225.000	¢ per kWh
Mid	155.000	¢ per kWh
Low	80.000	¢ per kWh

All Year Long

<table>
<tr><td rowspan="2"></td><td colspan="12">AM</td><td colspan="11">PM</td></tr>
<tr><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td></tr>
<tr><td>Standard Day
Seven Days a Week</td><td colspan="23">Std Block</td></tr>
<tr><td>Day with PTR
(when called*)</td><td colspan="14">Std Block</td><td colspan="5">PTR Window
2-5 Hours</td><td colspan="4">Std Block</td></tr>
</table>

* The Company will call Peak Time Rebate events only in Event Seasons. Events will not be called on Holidays. Customers pay energy charges based on a standard day, but are also eligible for a Peak Time Rebate.

** Determined by the Company upon enrollment.

Day/Night Time of Use

Energy Charge

Off-Peak Period	4.389	¢ per kWh	(R)
On-Peak Period	10.489	¢ per kWh	(R)
First 1,000 kWh block adjustment	(0.722)	¢ per kWh	

All Year Long

<table>
<tr><td rowspan="2"></td><td colspan="12">AM</td><td colspan="11">PM</td></tr>
<tr><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td></tr>
<tr><td>Standard Day
Mon. - Fri.</td><td colspan="6">Off Peak</td><td colspan="15">On Peak</td><td colspan="2">Off Peak</td></tr>
<tr><td>Saturdays, Sundays,
and Holidays</td><td colspan="23">Off Peak</td></tr>
</table>

SCHEDULE 6 (Continued)

MONTHLY RATE (Continued)

Day/Night Time of Use with PTR

Energy Charge

Off-Peak Period	4.389	¢ per kWh	(R)
On-Peak Period	10.489	¢ per kWh	(R)
First 1,000 kWh block adjustment	(0.722)	¢ per kWh	

Peak Time Rebate* (when called)
Credit at one of the following rates**:

High	225.000	¢ per kWh
Mid	155.000	¢ per kWh
Low	80.000	¢ per kWh

Summer Hours (May 1 – October 31)

	AM 1 2 3 4 5 6 7 8 9 10 11 12 / PM 1 2 3 4 5 6 7 8 9 10 11				
Standard Day Mon. - Fri.	Off Peak	On Peak			Off Peak
Day with PTR (when called*)	Off Peak	On Peak	PTR Window 2-5 Hours	On Peak	Off Peak
Saturdays, Sundays, and Holidays	Off Peak				

Winter Hours (November 1 – April 30)

		AM 1 2 3 4 5 6 7 8 9 10 11 12 / PM 1 2 3 4 5 6 7 8 9 10 11				
Standard Day Mon. - Fri.		Off Peak	On Peak			Off Peak
Day with PTR (when called*)	PM	Off Peak	On Peak	PTR Window 2-5 Hours	On Peak	Off Peak
	-or-					
	AM	Off Peak	On	PTR Window 2-4 Hours	On Peak	Off Peak
Saturdays, Sundays, and Holidays		Off Peak				

* The Company will call Peak Time Rebate events only in Event Seasons. Events will not be called on Holidays. Customers pay energy charges based on a standard day, but are also eligible for a Peak Time Rebate.
** Determined by the Company upon enrollment.

SCHEDULE 6 (Continued)

MONTHLY RATE (Continued)

Two Period Time of Use

Energy Charge

Off-Peak Period	5.216	¢ per kWh	(R)
On-Peak Period	14.516	¢ per kWh	(R)
First 1,000 kWh block adjustment	(0.722)	¢ per kWh	

Summer Hours (May 1 – October 31)

<table>
<tr><td rowspan="2"></td><td colspan="12">AM</td><td colspan="11">PM</td></tr>
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Mon. - Fri.</td><td colspan="14">Off Peak</td><td colspan="5">On Peak</td><td colspan="4">Off Peak</td></tr>
<tr><td>Saturdays, Sundays,
and Holidays</td><td colspan="23">Off Peak</td></tr>
</table>

Winter Hours (November 1 – April 30)

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<tr><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td></tr>
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Mon. - Fri.</td><td colspan="6">Off Peak</td><td colspan="4">On Peak</td><td colspan="4">Off Peak</td><td colspan="5">On Peak</td><td colspan="4">Off Peak</td></tr>
<tr><td>Saturdays, Sundays,
and Holidays</td><td colspan="23">Off Peak</td></tr>
</table>

SCHEDULE 6 (Continued)

MONTHLY RATE (Continued)

Two Period Time of Use with Peak Time Rebate

Energy Charge

Off-Peak Period	5.216	¢ per kWh	(R)
On-Peak Period	14.516	¢ per kWh	(R)
First 1,000 kWh block adjustment	(0.722)	¢ per kWh	

Peak Time Rebate* (when called)
Credit at one of the following rates**:

High	225.000	¢ per kWh
Mid	155.000	¢ per kWh
Low	80.000	¢ per kWh

Summer Hours (May 1 – October 31)

<table>
<tr><td rowspan="2"></td><td colspan="11">AM</td><td colspan="12">PM</td></tr>
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<tr><td>Standard Day Mon. - Fri.</td><td colspan="14">Off Peak</td><td colspan="5">On Peak</td><td colspan="4">Off Peak</td></tr>
<tr><td>Day with PTR (when called*)</td><td colspan="14">Off Peak</td><td colspan="5">PTR Window 2-5 Hours</td><td colspan="4">Off Peak</td></tr>
<tr><td>Saturdays, Sundays, and Holidays</td><td colspan="23">Off Peak</td></tr>
</table>

Winter Hours (November 1 – April 30)

<table>
<tr><td colspan="2" rowspan="2"></td><td colspan="11">AM</td><td colspan="12">PM</td></tr>
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</table>

* The Company will call Peak Time Rebate events only in Event Seasons. Events will not be called on Holidays. Customers pay energy charges based on a standard day, but are also eligible for a Peak Time Rebate.

** Determined by the Company upon enrollment.

SCHEDULE 6 (Continued)

MONTHLY RATE (Continued)

Three Period Time of Use

Energy Charge

Off-Peak Period	3.779	¢ per kWh	(R)
Mid-Peak Period	8.779	¢ per kWh	|
On-Peak Period	14.879	¢ per kWh	(R)
First 1,000 kWh block adjustment	(0.722)	¢ per kWh	

Summer Hours (May 1 – October 31)

	AM											PM											
	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11
Standard Day Mon. - Fri.	Off Peak										Mid Peak				On Peak					Mid Peak		Off Peak	
Saturdays, Sundays, and Holidays	Off Peak																						

Winter Hours (November 1 – April 30)

	AM											PM											
	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11
Standard Day Mon. - Fri.	Off Peak						On Peak				Mid Peak				On Peak					Mid Peak		Off Peak	
Saturdays, Sundays, and Holidays	Off Peak																						

SCHEDULE 6 (Continued)

MONTHLY RATE (Continued)

Three Period Time of Use with Peak Time Rebate

Energy Charge

Off-Peak Period	3.779	¢ per kWh	(R)
Mid-Peak Period	8.779	¢ per kWh	
On-Peak Period	14.879	¢ per kWh	(R)
First 1,000 kWh block adjustment	(0.722)	¢ per kWh	

Peak Time Rebate* (when called)
Credit at one of the following rates**:

High	225.000	¢ per kWh
Mid	155.000	¢ per kWh
Low	80.000	¢ per kWh

Summer Hours (May 1 – October 31)

<table>
<tr><td rowspan="2"></td><td colspan="12">AM</td><td colspan="11">PM</td></tr>
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Winter Hours (November 1 – April 30)

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* The Company will call Peak Time Rebate events only in Event Seasons. Events will not be called on Holidays. Customers pay energy charges based on a standard day, but are also eligible for a Peak Time Rebate.

** Determined by the Company upon enrollment.

SCHEDULE 7
RESIDENTIAL SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	\$11.50		(I)
Transmission and Related Services Charge	0.220	¢ per kWh	(R)
Distribution Charge	4.530	¢ per kWh	(I)
Energy Charge Options			
Standard Service			
First 1,000 kWh	6.795	¢ per kWh	(R)
Over 1,000 kWh	7.517	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio (Whole Premises or Electric Vehicle (EV) TOU) (Enrollment is necessary)			
On-Peak Period	13.121	¢ per kWh	
Mid-Peak Period	7.517	¢ per kWh	
Off-Peak Period	4.375	¢ per kWh	(R)
First 1,000 kWh block adjustment**	(0.722)	¢ per kWh	

* 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	0.128	¢ per kWh	(R)
Distribution Charge	6.510	¢ per kWh	(I)
Cost of Service Energy Charge	5.129	¢ 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	$ 13.03 (2)	(I)
	400	21,000	147	23.11 (2)	
	1,000	55,000	374	50.05 (2)	(I)
HPS	70	6,300	30	8.83 (2)	(R)
	100	9,500	43	10.36	(I)
	150	16,000	62	12.71	
	200	22,000	79	15.10	
	250	29,000	102	17.68	
	310	37,000	124	20.63 (2)	
	400	50,000	163	24.93	
Flood, HPS	100	9,500	43	10.26 (2)	
	200	22,000	79	15.31 (2)	
	250	29,000	102	17.96	
	400	50,000	163	25.14	(I)
Shoebox, HPS (bronze color, flat	70	6,300	30	10.15	(R)
lens or drop lens, multi-volt)	100	9,500	43	11.37	(R)
	150	16,500	62	13.93	(I)
Special Acorn Type, HPS	100	9,500	43	13.62	(R)
HADCO Victorian, HPS	150	16,500	62	15.86	
	200	22,000	79	18.52	(R)
	250	29,000	102	21.22	(I)
Early American Post-Top, HPS					
Black	100	9,500	43	10.74	(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	$ 12.89	(I)
	175	12,000	71	14.25	
Flood, Metal Halide	350	30,000	139	22.34	
	400	40,000	156	24.53	
Flood, HPS	750	105,000	285	42.72	(I)
HADCO Independence, HPS	100	9,500	43	13.76	(R)
	150	16,000	62	16.00	(I)
HADCO Capitol Acorn, HPS	100	9,500	43	17.21	(I)
	150	16,000	62	18.18	(R)
	200	22,000	79	20.19	
	250	29,000	102	22.88	
HADCO Techtra, HPS	100	9,500	43	22.11	
	150	16,000	62	24.13	
	250	29,000	102	28.65	
HADCO Westbrooke, HPS	70	6,300	30	14.63	
	100	9,500	43	15.74	(R)
	150	16,000	62	22.53	(I)
	200	22,000	79	20.16	(R)
	250	29,000	102	23.43	(I)
Holophane Mongoose, HPS	150	16,000	62	16.24	(R)

(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	60	5,488	21	$ 13.53	(R)
	70	4,332	24	15.52	|
HADCO LED	70	5,120	24	18.41	(R)
Cobrahead Equivalent					
LED	37	2,530	13	4.81	(I)
	50	3,162	17	5.28	|
	52	3,757	18	5.73	|
	67	5,050	23	6.52	|
	106	7,444	36	8.81	(I)
	134	14,200	46	11.80	(R)
	156	16,300	53	13.75	|
	176	18,300	60	14.98	|
	201	21,400	69	15.34	|
Westbrooke LED (Non-Flare)	36	3,369	12	14.61	|
	53	5,079	18	17.01	|
	69	6,661	24	17.33	(R)
	85	8,153	29	18.93	(I)
	136	12,687	46	22.95	(R)
	206	18,159	70	25.50	|
Westbrooke LED (Flare)	36	3,369	12	15.64	|
	53	5,079	18	18.96	|
	69	6,661	24	19.66	|
	85	8,153	29	19.28	|
	136	12,687	46	23.97	|
	206	18,159	70	26.80	(R)
CREE XSP LED	25	2,529	9	3.50	(I)
	42	3,819	14	4.17	|
	48	4,373	16	4.80	(I)
	56	5,863	19	5.59	
	91	8,747	31	7.00	(I)
Post-Top, American Revolution					|
LED	45	3,395	15	7.81	(I)
	72	4,409	25	8.46	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole Rates for Area Light Poles[1]	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$ 5.08	(R)
	40 to 55	6.63	
Wood, Painted for Underground	35 or less	5.08 [2]	
Wood, Curved Laminated	30 or less	6.28 [2]	
Aluminum, Regular	16	6.03	
	25	10.01	
	30	10.81	
	35	12.92	
Aluminum, Fluted Ornamental	14	8.81	
Aluminum Davit	25	9.99	
	30	9.95	
	35	10.87	
	40	14.73	
Aluminum Double Davit	30	14.64	
Aluminum, Fluted Ornamental	16	9.00	
Aluminum, HADCO, Smooth Techtra Ornamental	18	17.32	
Aluminum, HADCO, Fluted Westbrooke	18	17.36	
Aluminum, HADCO, Smooth Westbrooke	18	18.40	
Concrete Ameron Post-Top	25	17.28	(R)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole Rates for Area Light Poles[1]	Pole Length (feet)	Monthly Rate Per Pole	
Fiberglass Fluted Ornamental; Black	14	$ 10.66	(R)
Fiberglass, Regular			
Black	20	4.46	
Gray or Bronze	30	7.57	
Black, Gray, or Bronze	35	6.51	
Fiberglass, Anchor Base, Gray or Black	35	11.83	
Fiberglass, Direct Bury with Shroud	18	7.19	(R)

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.

Portland General Electric Company
P.U.C. Oregon No. E-18

Tenth Revision of Sheet No. 32-1
Canceling Ninth Revision of Sheet No. 32-1

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 Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$18.00		(I)
Three Phase Service	$24.00		(I)
Transmission and Related Services Charge	0.185	¢ per kWh	(R)
Distribution Charge			
First 5,000 kWh	4.522	¢ per kWh	(I)
Over 5,000 kWh	0.947	¢ per kWh	(R)
Energy Charge Options			
Standard Service	6.195	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.927	¢ per kWh	
Mid-Peak Period	6.195	¢ per kWh	
Off-Peak Period	3.645	¢ 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 0.309¢ per kWh for wheeling (I)
- times a loss adjustment factor of 1.0685

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 voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2015.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$25.00		
Transmission and Related Services Charge	0.153	¢ per kWh	(R)
Distribution Charge	7.568	¢ per kWh	(I)
Energy Charge*			
On-Peak Period	6.171	¢ per kWh	(R)
Off-Peak Period	5.171	¢ 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 0.309¢ per kWh for wheeling, plus **(I)** losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0685

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 Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$35.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.190	¢ per kWh	(R)
Distribution Charge			
First 50 kWh per kW of Demand***	11.482	¢ per kWh	(I)
Over 50 kWh per kW of Demand	9.482	¢ per kWh	(I)
Energy Charge	7.146	¢ 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 Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$40.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.190	¢ per kWh	(R)
Distribution Charge			
First 50 kWh per kW of Demand***	8.631	¢ per kWh	(I)
Over 50 kWh per kW of Demand	6.631	¢ per kWh	(I)
Energy Charge	7.092	¢ 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 Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,350.00	$1,910.00	$4,080.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.70	$0.68	$0.67	(R)
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.65	$1.61	$1.61	(I)
Over 4,000 kW	$1.34	$1.30	$1.30	
per kW of monthly On-Peak Demand	$2.84	$2.76	$1.36	(I)
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	0.232 ¢	0.228 ¢	0.225 ¢	(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 0.309¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, (I)
plus losses.

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	$0.027	$0.026	$0.026	(R)
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.111	$0.108	$0.053	(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 0.309¢ per kWh for wheeling, plus (I) losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported.

Daily ERP: The Daily ERP Energy Charge will be determined in accordance with a commodity energy price quote from the Company accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.309¢ per kWh for wheeling, plus (I) losses. Customer will communicate with PGE between hour 0615 and 0625 to receive the PGE commodity energy price quote based on the customer's submitted ENF for the day of delivery. Customer will state acceptance of quote within 5 minutes of receipt of quote from the Company. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

Monthly ERP: The Monthly ERP Energy Charge will be determined in accordance with a price quote accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.309¢ per kWh for wheeling, plus losses. At customer request and based on (I) the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated.

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ERP Pricing (Continued)

The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

On-peak hours (Heavy Load Hours, HLH) are between 6:00 a.m. and 10:00 p.m. PPT (hours ending 0700 through 2200), Monday through Saturday. Off-peak hours (Light Load Hours, LLH) are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all hours Sunday.

Losses will be included by multiplying the ERP Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

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 0.309¢ per kWh for wheeling, plus losses. (I)
- 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 0.309¢ per kWh for wheeling, plus losses. (I)

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 0.309¢ per kWh for wheeling, plus losses. (I)

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 0.309¢ per kWh for wheeling, plus losses. (I)

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 0.309¢ per kWh (I)
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	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

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 Point of Delivery (POD)*:

Basic Charge		
Single Phase Service	$30.00	
Three Phase Service	$40.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.70	(R)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$3.84	(I)
Over 30 kW	$3.74	|
per kW of monthly On-Peak Demand	$2.84	(I)
Energy Charge (per kWh)		
On-Peak Period***	6.618 ¢	(R)
Off-Peak Period***	5.118 ¢	|
See below for Daily Pricing Option description.		|
System Usage Charge		|
per kWh	0.690 ¢	(R)

* 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 POD.

*** 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 0.309¢ 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. (I)

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0685

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 Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$530.00	$490.00	(I)
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.70	$0.68	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.50	$3.42	(I)
Over 200 kW	$2.60	$2.52	|
per kW of monthly On-Peak Demand	$2.84	$2.76	(I)
Energy Charge (per kWh)			
On-Peak Period***	6.441 ¢	6.332 ¢	(R)
Off-Peak Period***	4.941 ¢	4.832 ¢	|
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.151 ¢	0.146 ¢	(R)

* 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 POD.
*** 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 0.309¢ 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. **(I)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

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 Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,350.00	$1,910.00	$4,080.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.70	$0.68	$0.67	(R)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.65	$1.61	$1.61	(I)
Over 4,000 kW	$1.34	$1.30	$1.30	
per kW of monthly On-Peak Demand	$2.84	$2.76	$1.36	(I)
Energy Charge (per kWh)				
On-Peak Period***	6.155 ¢	6.054 ¢	5.979 ¢	(R)
Off-Peak Period***	4.655 ¢	4.554 ¢	4.479 ¢	(R)
See below for Daily Pricing Option description.				
System Usage Charge				
per kWh	0.232 ¢	0.228 ¢	0.225 ¢	(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 POD.

*** 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 0.309¢ per kWh for wheeling, plus (I) 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	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

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 >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$5,600.00	(R)
Transmission and Related Services Charge per kW of monthly On-Peak Demand	$0.68	(R)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.48	(I)
Over 4,000 kW	$1.17	
per kW of monthly on-peak Demand	$2.76	(I)
Energy Charge (per kWh)		
On-Peak Period***	5.996 ¢	(R)
Off-Peak Period***	4.496 ¢	
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.100 ¢	(R)

* 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 POD.

*** 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 0.309¢ 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. **(I)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

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	0.128 ¢ per kWh	(R)
Distribution Charge	6.510 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.129 ¢ 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 0.309¢ per kWh for wheeling, plus losses. If prices are not (I) reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0685.

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	*	$ 1.27	(R)
	100	9,500	43	*	1.27	
	150	16,000	62	*	1.28	
	200	22,000	79	*	1.31	
	250	29,000	102	*	1.29	
	400	50,000	163	*	1.33	
Cobrahead	70	6,300	30	$ 4.41	1.50	
	100	9,500	43	4.41	1.50	
	150	16,000	62	4.52	1.51	
	200	22,000	79	5.24	1.57	
	250	29,000	102	5.12	1.55	
	400	50,000	163	5.19	1.56	
Flood	250	29,000	102	5.40	1.58	
	400	50,000	163	5.40	1.58	
Early American Post-Top	100	9,500	43	4.79	1.55	
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	5.73	1.68	
	100	9,500	43	5.42	1.64	
	150	16,000	62	5.74	1.68	(R)

* Not offered.
** Service is only available to Customers with total power door luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black, Bronze, or Gray	20	$ 4.46	$ 0.14	(R)
Fiberglass, Black or Bronze	30	7.03	0.23	
Fiberglass, Gray	30	7.57	0.25	
Fiberglass, Smooth, Black or Bronze	18	4.46	0.14	
Fiberglass, Regular				
Black, Bronze, or Gray	18	3.98	0.13	
	35	6.51	0.21	(R)

SCHEDULE 91 (Continued)

RATES FOR STANDARD POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Wood, Standard	30 to 35	$ 5.08	$ 0.16	(R)
Wood, Standard	40 to 55	6.63	0.22	(R)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Acorn-Types						
HPS	100	9,500	43	$ 8.00	$ 1.94	(R)
HADCO Victorian, HPS	150	16,000	62	8.00	1.94	
	200	22,000	79	8.67	2.03	
	250	29,000	102	8.67	2.03	
HADCO Capitol Acorn, HPS	100	9,500	43	11.60	2.41	
	150	16,000	62	10.33	2.24	
	200	22,000	79	10.34	2.25	
	250	29,000	102	10.33	2.24	
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	8.14	1.94	
	150	16,000	62	8.14	1.94	
HADCO Techtra, HPS	100	9,500	43	16.50	3.06	
	150	16,000	62	16.28	3.03	
	250	29,000	102	16.10	3.00	
HADCO Westbrooke, HPS	70	6,300	30	10.55	2.27	
	100	9,500	43	10.12	2.21	
	150	16,000	62	14.68	2.81	
	200	22,000	79	10.30	2.24	
	250	29,000	102	10.87	2.31	(R)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Types						
Flood, Metal Halide	350	30,000	139	$ 5.43	$ 1.74	(R)
Flood, HPS	750	105,000	285	8.62	2.82	(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	Option B	
Aluminum, Regular	25	$ 10.01	$ 0.32	(R)
	30	10.81	0.35	
	35	12.92	0.42	
Aluminum Davit	25	9.99	0.32	
	30	9.95	0.32	
	35	10.87	0.35	
	40	14.73	0.48	
Aluminum Double Davit	30	14.64	0.47	(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	$ 8.81	$ 0.29	(R)
Aluminum, HADCO, Smooth Techtra Ornamental	18	17.32	0.56	
Aluminum, Fluted Ornamental	16	9.00	0.29	
Aluminum, HADCO, Fluted Westbrooke	18	17.36	0.56	
Aluminum, HADCO, Smooth Westbrooke	18	18.40	0.60	
Fiberglass, Fluted Ornamental Black	14	10.66	0.35	
Fiberglass, Anchor Base, Gray or Black	35	11.83	0.38	(R)

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	$4.94	$ 1.78	(R)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	4.37	1.46	
	250	10,000	94	*	*	
	400	21,000	147	5.25	1.58	
	1,000	55,000	374	5.48	1.85	
Holophane Mongoose, HPS	150	16,000	62	8.39	1.99	
	250	29,000	102	7.84	1.92	
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	5.37	*	
Mercury Vapor	175	7,000	66	5.33	1.55	(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	*	$ 1.89	(R)
	150	16,000	62	*	1.91	
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	1.24	
	400	40,000	156	*	1.24	
Cobrahead, Metal Halide	175	12,000	71	*	1.65	
Flood, Metal Halide	400	40,000	156	$ 5.62	1.80	
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	1.52	
100/150 Watt Ballast	100	9,500	43	*	1.52	
100/150 Watt Ballast	150	16,000	62	*	1.53	
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.70	
	165	12,000	60	*	0.83	
HADCO Techtra, QL	165	12,000	60	17.55	1.09	
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	2.38	
KIM Archetype, HPS	250	29,000	102	*	2.43	
	400	50,000	163	*	2.12	
Special Acorn-Type, HPS	70	6,300	30	8.02	1.96	(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	$ 4.73	$ 1.49	(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	4.73	1.49	
Flood, HPS	70	6,300	30	4.32	1.41	
	100	9,500	43	4.31	1.51	
	200	22,000	79	5.45	1.63	
Cobrahead, HPS						
Power Door	310	37,000	124	5.48	1.91	(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	$ 6.03	*	(R)
Aluminum, Painted Ornamental	35	*	$ 0.96	
Aluminum, Regular	16	6.03	0.20	
Bronze Alloy GardCo	12	*	0.18	
Concrete, Ornamental	35 or less	10.01	0.32	
Fiberglass, Direct Bury with Shroud	18	7.19	0.23	
Steel, Painted Regular **	25	10.01	0.32	
Steel, Painted Regular **	30	10.81	0.35	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.32	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.32	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.35	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.35	
Wood, Laminated without Mast Arm	20	4.46	0.14	
Wood, Laminated Street Light Only	20	4.46	*	
Wood, Curved Laminated	30	6.28	0.23	
Wood, Painted Underground	35	5.08	0.16	(R)

* 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 Point of Delivery (POD)*:

Transmission and Related Services Charge	0.139	¢ per kWh	(R)
Distribution Charge	2.790	¢ per kWh	(I)
Energy Charge	5.339	¢ 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)

STREETLIGHT POLES SERVICE OPTIONS

See Schedule 91 for Streetlight poles service options.

MONTHLY RATE

In addition to the service rates for Option A 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	0.128 ¢ per kWh	(R)
Distribution Charge	6.510 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.129 ¢ 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 0.309¢ 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. (I)

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 1.0685.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

SCHEDULE 95 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate	Straight Time	Overtime [1]
	$135.00 per hour	$193.00 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 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 Rate Option A	
Cobrahead Equivalent	37	2,530	13	$ 2.89	
Cobrahead Equivalent	50	3,162	17	2.89	
Cobrahead Equivalent	52	3,757	18	3.22	
Cobrahead Equivalent	67	5,050	23	3.54	(R)
Cobrahead Equivalent	106	7,444	36	4.31	(I)
Cobrahead Equivalent	134	14,200	46	6.79	(R)
Cobrahead Equivalent	156	16,300	53	7.91	|
Cobrahead Equivalent	176	18,300	60	8.32	|
Cobrahead Equivalent	201	21,400	69	7.62	(R)

SCHEDULE 95 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$ 10.51	(R)
	70	4,332	24	12.15	
HADCO Acorn LED	70	5,120	24	16.00	
Westbrooke (Non-Flared)	36	3,369	12	13.61	
LED	53	5,079	18	14.34	
	69	6,661	24	13.96	
	85	8,153	29	14.97	
	136	12,687	46	16.99	
	206	18,159	70	16.71	
Westbrooke (Flared)	36	3,369	12	14.63	
LED	53	5,079	18	16.28	
	69	6,661	24	16.28	
	85	8,153	29	15.31	
	136	12,687	46	18.00	
	206	18,159	70	18.00	(R)
Post-Top, American Revolution	45	3,395	15	6.44	(I)
LED	72	4,409	25	5.93	(R)

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 122
RENEWABLE RESOURCES AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource projects (including associated transmission) not otherwise included in rates. Additional new renewable projects 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 and 576. 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				
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				
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 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 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 plus any power costs such as fuel, integration and wheeling costs) will be deferred and incorporated the following January 1 into the Schedule 122 rates. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts. Each year by April 1, 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.

DEFERRAL MECHANISM

For each calendar year that the Company anticipates that a new renewable resource 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 amortization of the deferred amount will not be subject to the provisions of ORS 757.259(5).

SCHEDULE 123
DECOUPLING ADJUSTMENT

PURPOSE

This Schedule establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Point of Delivery during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer. Customers so exempted will not be charged the prices contained in this schedule.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

Energy Efficiency Measures (EEMs) – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.

Self-Directing Customer (SDC) - Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy as an SDC.

SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, for Customers served under Schedules 7, 32 and 532,
differences between a) the monthly revenues resulting from applying distribution, transmission
and fixed generation charges (Fixed Charge Energy Rate) of 9.158 cents/kWh for Schedule 7 (I)
and 8.210 cents/kWh for Schedules 32 and 532 to weather-normalized kWh Energy sales, and (I)
b) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge
per Customer of $74.73 per month for Schedule 7 and $115.50 per month for Schedules 32 and (I)
532 to the numbers of active Schedule 7 and Schedule 32 and 532 Customers, respectively, for
each month. For Schedule 7, a Secondary Fixed Charge equal to 69% of the Monthly Fixed (C)
Charge will be used to calculate Fixed Charge Revenues for actual customer counts that
exceed the projected customer counts used to establish base rates in a general rate review.
The Schedule 7 Secondary Fixed Charge is $51.56. (I)

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

The SNA will calculate monthly as the Fixed Charge Revenue less actual weather-adjusted 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 Schedule 7 will track separately from the net accruals for Schedules 32 and 532.

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 or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. Also included are differences in actual energy savings from a test year forecast associated with the conversion to LED streetlighting in Schedule 95 reported by the Company. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates.

The Lost Revenue Recovery Adjustment may be positive or negative. A negative Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are less than those estimated in setting base rates. A positive Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are greater than those estimated for the test year in setting base rates. The LRRA for each year subsequent to the test year will incorporate incremental kWh savings reported by the Energy Trust of Oregon for that year.

For the purposes of this Schedule, the Lost Revenue Recovery Adjustment is the product of: (1) the reduction in kWh sales resulting from ETO-reported EEMs plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, and (2) the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule-weighted average of transmission, distribution, and fixed generation charges; including those contained in Schedule122 and other applicable schedules. System usage or distribution charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. Franchise fee recovery is not included in the Lost Revenue Rate. The applicable Lost Revenue Rate is 6.472 cents per kWh. (I)

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. (R)

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 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	(I)
15		0.000	
32		0.000	
38	Large Nonresidential	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	(I)

(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 and 595, 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 **(R)** to account for franchise fees, uncollectibles, and OPUC fees.

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, and 495 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. **(R)**

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

SCHEDULE 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 2017, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2018: (C)
(C)

Schedule		Annual ¢ per kWh [1]	
32		3.377	(R)
38		2.821	
75	Secondary	2.747 [2]	
	Primary	2.696 [2]	
	Subtransmission	2.716 [2]	
83		3.285	
85	Secondary	3.104	
	Primary	3.014	(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	2.747	(R)
	Primary	2.696	
	Subtransmission	2.716	
90		2.627	
91		2.492	
95		2.492	
515		2.492	
532		3.377	
538		2.821	
549		4.325	
575	Secondary	2.747 [(2)]	
	Primary	2.696 [(2)]	
	Subtransmission	2.716 [(2)]	
583		3.285	
585	Secondary	3.104	
	Primary	3.014	
589	Secondary	2.747	
	Primary	2.696	
	Subtransmission	2.716	
590		2.627	
591		2.492	
592		2.553	
595		2.492	(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.

Portland General Electric Company
P.U.C. Oregon No. E-18

Seventeenth Revision of Sheet No. 129-2
Canceling Sixteenth Revision of Sheet No. 129-2

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

For Enrollment Period L (2013), the Transition Cost Adjustment will be:

Period	Sch. 485 Secondary Voltage ¢ per kWh	Sch. 485 Primary Voltage ¢ per kWh	Sch. 489 Secondary Voltage ¢ per kWh	Sch. 489 Primary Voltage ¢ per kWh	Sch. 489 Subtransmission Voltage ¢ per kWh
2014	1.992	1.956	1.398	1.728	1.709
2015	1.718	1.695	1.113	1.466	1.450
2016	1.482	1.466	0.860	1.239	1.226
2017	1.228	1.223	0.589	0.997	0.987
2018	1.154	1.147	0.483	0.921	0.914
After 2018	0.000	0.000	0.000	0.000	0.000

Commencing with enrollment Period M, 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 M (2014), 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	
2015	1.712	1.704	1.443	1.415	1.383	1.381	1.311	
2016	2.172	2.151	1.890	1.854	1.824	1.798	1.789	
2017	2.196	2.174	1.913	1.876	1.846	1.820	1.811	
2018	2.448	2.426	2.125	2.079	2.038	2.006	1.894	(I)
2019	2.448	2.426	2.125	2.079	2.038	2.006	1.894	(I)
After 2019	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

Commencing with enrollment Period M, 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 N (2015), 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	
2016	2.866	2.832	2.695	2.647	2.590	2.295	2.455	
2017	2.890	2.855	2.718	2.669	2.612	2.317	2.477	
2018	3.142	3.107	2.930	2.872	2.804	2.503	2.560	(I)
2019	3.142	3.107	2.930	2.872	2.804	2.503	2.560	|
2020	3.142	3.107	2.930	2.872	2.804	2.503	2.560	(I)
After 2020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

For Enrollment Period O (2016), 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	
2017	3.015	2.963	2.854	2.803	2.739	2.431	2.586	
2018	3.204	3.153	3.001	2.948	2.874	2.559	2.612	(I)
2019	3.204	3.153	3.001	2.948	2.874	2.559	2.612	|
2020	3.204	3.153	3.001	2.948	2.874	2.559	2.612	|
2021	3.204	3.153	3.001	2.948	2.874	2.559	2.612	|
After 2021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(I)

SCHEDULE 129 (Concluded)

SPECIAL CONDITIONS (Continued)

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	3.997	(I)
	Primary	3.927	
89	Secondary	3.745	
	Primary	3.676	
	Subtransmission	3.627	
90		3.622	
91		3.474	
92		3.474	
95		3.474	(I)

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.

Portland General Electric Company
P.U.C. Oregon No. E-18

First Revision of Sheet No. 146-1
Canceling Original Sheet No. 146-1

SCHEDULE 146
COLSTRIP POWER PLANT
OPERATING LIFE ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the Company's share of the revenue requirement effect of the change in the Colstrip Power Plant Units 3 and 4 and associated common facilities currently assumed end of depreciable life year from 2042 to 2030 as specified in 2016 Oregon Laws, Chapter 28 (SB 1547), Section 1. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495 and 576R.

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	0.000	¢ per kWh	(R)
15/515	0.000	¢ per kWh	
32/532	0.000	¢ per kWh	
38/538	0.000	¢ per kWh	
47	0.000	¢ per kWh	
49/549	0.000	¢ per kWh	
75/575			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
83/583	0.000	¢ per kWh	
85/585			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
89/589			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	(R)

SCHEDULE 146 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
90/590	0.000	¢ per kWh	(R)
91/591	0.000	¢ per kWh	
92/592	0.000	¢ per kWh	
95/595	0.000	¢ per kWh	(R)

DETERMINATION OF ADJUSTMENT AMOUNT

Any revision to this schedule's Adjustment Rates requires Commission authorization (by order, approval of a filing, acknowledgement of an Integrated Resource Plan's Action Plan, or approval of a depreciation study) to revise for rate setting and accounting purposes, the end of depreciable life assumption of 2042 for the Colstrip Power Plant Units 3 and 4 and associated common facilities. The revised Adjustment Rates will be set to recover an Adjustment Amount reflecting the change in depreciation revenue requirements.

The Adjustment Amount is the difference between the Colstrip Power Plant Units 3 and 4 and associated common facilities depreciation/amortization revenue requirement for the year 2017 as determined in UE 294 that reflects a plant end of depreciable life date of 2042, and the same depreciation/amortization revenue requirement determination using a plant end of depreciable life assumption of 2030. The depreciation/amortization revenue requirement change computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return, and return on equity rates. Only changes to depreciation expense, amortization expense and related Schedule M and rate base adjustments as of the date of the filing revisions to this rate schedule are included in the depreciation/amortization revenue requirements.

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 depreciation revenue requirement, if the Company has not incorporated the revised depreciable life into base rates in a general rate case or other proceeding.

The docket reference numbers and dates in this schedule will be revised as necessary to a subsequent docket if no change to the Colstrip Power Plant Units 3 and 4 and associated common facilities depreciable life occurs prior to a subsequent general rate case order.

TERM

This schedule will terminate at the date that base rates include the revised end of life assumption or when all remaining investment in the Colstrip Power Plant Units 3 and 4 and associated facilities have been recovered.

SCHEDULE 485 (Continued)

CHANGE IN APPLICABILITY

If a Customer's usage changes such that their facility capacity falls below 201 kW, they will have their service terminated under this schedule and will be moved to an otherwise applicable schedule.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$530.00	$490.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.50	$3.42	(I)
Over 200 kW	$2.60	$2.52	|
per kW of monthly On-Peak Demand	$2.84	$2.76	(I)
System Usage Charge			
per kWh	0.012 ¢	0.010 ¢	(R)

* 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 POD.

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 POD 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 485 (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 $1.802 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.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly On-Peak Demand (in kW) will be 100 kW for primary voltage service.

SCHEDULE 489 (Continued)

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,350.00	$1,910.00	$4,080.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.65	$1.61	$1.61	
Over 4,000 kW	$1.34	$1.30	$1.30	
per kW of monthly On-Peak Demand	$2.84	$2.76	$1.36	(I)
System Usage Charge				
per kWh	0.102 ¢	0.101 ¢	0.100 ¢	(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 POD.

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 POD 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 489 (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 $1.802 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.

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.

SCHEDULE 490 (Continued)

MONTHLY RATE

The Monthly Rate will be the sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$5,600.00	(R)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.48	(I)
Over 4,000 kW	$1.17	
per kW of monthly On-Peak Demand	$2.76	(I)
System Usage Charge		
per kWh	(0.042) ¢	(R)

* 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 POD.

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 POD 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 490 (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 $1.802 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.

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.

SCHEDULE 491 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	6.374 ¢ 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 POD 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 $1.802 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	1.0685

SCHEDULE 491 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$135.00 per hour	$193.00 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	*	$ 3.18	$ 1.91	(I)
	100	9,500	43	*	4.01	2.74	
	150	16,000	62	*	5.23	3.95	
	200	22,000	79	*	6.35	5.04	
	250	29,000	102	*	7.79	6.50	
	400	50,000	163	*	11.72	10.39	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.32	3.41	1.91	
	100	9,500	43	7.15	4.24	2.74	
	150	16,000	62	8.47	5.46	3.95	
	200	22,000	79	10.28	6.61	5.04	
	250	29,000	102	11.62	8.05	6.50	
	400	50,000	163	15.58	11.95	10.39	
Flood	250	29,000	102	11.90	8.08	6.50	
	400	50,000	163	15.79	11.97	10.39	
Early American Post-Top	100	9,500	43	7.53	4.29	2.74	
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	7.64	3.59	1.91	
	100	9,500	43	8.16	4.38	2.74	
	150	16,000	62	9.69	5.63	3.95	(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	Option B	
Fiberglass, Black, Bronze or Gray	20	$ 4.46	$ 0.14	(R)
Fiberglass, Black or Bronze	30	7.03	0.23	
Fiberglass, Gray	30	7.57	0.25	
Fiberglass, Smooth, Black or Bronze	18	4.46	0.14	
Fiberglass, Regular	18	3.98	0.13	
Black, Bronze, or Gray	35	6.51	0.21	
Wood, Standard	30 to 35	5.08	0.16	
Wood, Standard	40 to 55	6.63	0.22	(R)

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	$ 10.74	$ 4.68	$ 2.74	(I)	(I)	(I)
HADCO Victorian, HPS	150	16,000	62	11.95	5.89	3.95			
	200	22,000	79	13.71	7.07	5.04			
	250	29,000	102	15.17	8.53	6.50			
HADCO Capitol Acorn, HPS	100	9,500	43	14.34	5.15	2.74			
	150	16,000	62	14.28	6.19	3.95	(I)		
	200	22,000	79	15.38	7.29	5.04	(R)		
	250	29,000	102	16.83	8.74	6.50	(I)		
Special Architectural Types									
HADCO Independence, HPS	100	9,500	43	10.88	4.68	2.74	(R)		
	150	16,000	62	12.09	5.89	3.95	(I)		
HADCO Techtra, HPS	100	9,500	43	19.24	5.80	2.74	(R)		
	150	16,000	62	20.23	6.98	3.95	(R)		
	250	29,000	102	22.60	9.50	6.50	(I)		
HADCO Westbrooke, HPS	70	6,300	30	12.46	4.18	*	(R)		
	100	9,500	43	12.86	4.95	2.74	(R)	(I)	(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	$ 18.63	$ 6.76	$ 3.95	(I)
	200	22,000	79	15.34	7.28	5.04	
	250	29,000	102	17.37	8.81	6.50	
Special Types							
Flood, Metal Halide	350	30,000	139	14.29	10.60	8.86	
Flood, HPS	750	105,000	285	26.79	20.99	18.17	
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	4.08	
Ornamental Acorn	55	2,800	21	*	*	1.34	
Ornamental Acorn Twin	55	5,600	42	*	*	2.68	
Composite, Twin	140	6,815	54	*	*	3.44	
	175	9,815	66	*	*	4.21	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$ 10.01	$ 0.32	(R)
	30	10.81	0.35	
	35	12.92	0.42	
Aluminum Davit	25	9.99	0.32	
	30	9.95	0.32	
	35	10.87	0.35	
	40	14.73	0.48	
Aluminum Double Davit	30	14.64	0.47	
Aluminum, Fluted Ornamental	14	8.81	0.29	(R)

* 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, HADCO, Smooth Techtra Ornamental	18	$ 17.32	$ 0.56	(R)
Aluminum, Fluted Ornamental	16	9.00	0.29	
Aluminum, HADCO, Fluted Westbrooke	18	17.36	0.56	
Aluminum, HADCO, Smooth Westbrooke	18	18.40	0.60	
Fiberglass, Fluted Ornamental Black	14	10.66	0.35	
Fiberglass, Anchor Base, Gray or Black	35	11.83	0.38	(R)

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	$ 8.76	$ 5.60	$ 3.82	(I)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.49	
	175	7,000	66	8.58	5.67	4.21	
	250	10,000	94	*	*	5.99	
	400	21,000	147	14.62	10.95	9.37	
	1,000	55,000	374	29.32	25.69	23.84	
Holophane Mongoose, HPS	150	16,000	62	12.34	5.94	3.95	
	250	29,000	102	14.34	8.42	*	(I)

* Not offered.

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$ 7.28	*	*	
Mercury Vapor	175	7,000	66	9.54	$ 5.76	$ 4.21	(I)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	3.82	
	70	6,300	30	*	*	1.91	
	100	9,500	43	*	4.63	2.74	
	150	16,000	62	*	5.86	3.95	
	250	29,000	102	*	*	6.50	
	400	50,000	163	*	*	10.39	
Metal Halide	250	20,500	99	*	7.55	6.31	
	400	40,000	156	*	11.18	*	
Cobrahead, Metal Halide	175	12,000	71	*	6.18	4.53	
Flood, Metal Halide	400	40,000	156	15.56	11.74	9.94	
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	4.26	*	
100/150 Watt Ballast	100	9,500	43	*	4.26	*	
100/150 Watt Ballast	150	16,000	62	*	5.48	3.95	
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	6.33	3.95	
KIM Archetype, HPS	250	29,000	102	*	8.93	6.50	
	400	50,000	163	*	12.51	10.39	(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	$ 9.93	$ 3.87	*	(R)	(I)
Special GardCo Bronze Alloy								
HPS	70	5,000	30	*	*	$ 1.91		
Mercury Vapor	175	7,000	66	*	*	4.21		
Early American Post-Top, HPS								
Black	70	6,300	30	6.64	3.40	1.91		
Rectangle Type	200	22,000	79	*	*	5.04		
Incandescent	92	1,000	31	*	*	1.98		
	182	2,500	62	*	*	3.95		
Town and Country Post-Top								
Mercury Vapor	175	7,000	66	8.94	5.70	4.21		
Flood, HPS	70	6,300	30	6.23	3.32	*		
	100	9,500	43	7.05	4.25	2.74		
	200	22,000	79	10.49	6.67	5.04		
Cobrahead, HPS								
Power Door	310	37,000	124	13.38	9.81	7.90		
Special Types Customer-Owned & Maintained								
Ornamental, HPS	100	9,500	43	*	*	2.74		
Twin ornamental, HPS	Twin 100	9,500	86	*	*	5.48		
Compact Fluorescent	28	N/A	12	*	*	0.76		(I)

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 6.03	*	(R)
Aluminum, Painted Ornamental	35	*	$ 0.96	
Aluminum, Regular	16	6.03	0.20	
Bronze Alloy GardCo	12	*	0.18	
Concrete, Ornamental	35 or less	10.01	0.32	
Fiberglass, Direct Bury with Shroud	18	7.19	0.23	
Steel, Painted Regular **	25	10.01	0.32	
Steel, Painted Regular **	30	10.81	0.35	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.32	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.32	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.35	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.35	
Wood, Laminated without Mast Arm	20	4.46	0.14	
Wood, Laminated Street Light Only	20	4.46	*	
Wood, Curved Laminated	30	6.28	0.23	
Wood, Painted Underground	35	5.08	0.16	(R)

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C			
Special Architectural Types Including Philips QL Induction Lamp Systems									
HADCO Victorian, QL	85	6,000	32	*	$ 2.74	$ 2.04		(I)	(I)
	165	12,000	60	*	4.65	3.82			
	165	12,000	60	$ 21.37	4.91	3.82	(R)	(I)	(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 Point of Delivery (POD)* is:

Distribution Charge	2.648 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD 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 $1.802 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	1.0685

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 – Poles

See Schedule 91/491/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 6.374 ¢ 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 POD 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 $1.802 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	1.0685

SCHEDULE 495 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [(1)]	Straight Time	Overtime
	$135.00 per hour	$193.00 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 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 Rate Option A	
LED	37	2,530	13	$ 3.72	(I)
LED	50	3,162	17	3.97	|
LED	52	3,757	18	4.37	|
LED	67	5,050	23	5.01	|
LED	106	7,444	36	6.60	(I)
LED	134	14,200	46	9.72	(R)
LED	156	16,300	53	11.29	(I)
LED	176	18,300	60	12.14	(I)
LED	201	21,400	69	12.02	(R)

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$ 11.85	(R)
	70	4,332	24	13.68	
HADCO Acorn LED	70	5,120	24	17.53	
Westbrooke (Non-Flared)	36	3,369	12	14.37	
LED	53	5,079	18	15.49	
	69	6,661	24	15.49	(R)
	85	8,153	29	16.82	(I)
	136	12,687	46	19.92	(R)
	206	18,159	70	21.17	
Westbrooke (Flared)	36	3,369	12	15.39	
LED	53	5,079	18	17.43	
	69	6,661	24	17.81	
	85	8,153	29	17.16	
	136	12,687	46	20.93	
	206	18,159	70	22.46	(R)
Post-Top, American Revolution	45	3,395	15	7.40	(I)
LED	72	4,409	25	7.52	(I)

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.

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

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$ 9.47 (2)	(I)
	400	21,000	147	15.18 (2)	
	1,000	55,000	374	29.88 (2)	
HPS	70	6,300	30	7.21 (2)	
	100	9,500	43	8.04	
	150	16,000	62	9.36	
	200	22,000	79	10.84	
	250	29,000	102	12.18	
	310	37,000	124	13.94 (2)	
	400	50,000	163	16.14	
Flood , HPS	100	9,500	43	7.94 (2)	
	200	22,000	79	11.05 (2)	
	250	29,000	102	12.46	
	400	50,000	163	16.35	
Shoebox, HPS (bronze color, flat lens,	70	6,300	30	8.53	
or drop lens, multi-volt)	100	9,500	43	9.05	
	150	16,500	62	10.58	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Special Acorn Type, HPS	100	9,500	43	$ 11.30	(I)
HADCO Victorian, HPS	150	16,500	62	12.51	
	200	22,000	79	14.26	
	250	29,000	102	15.72	
Early American Post-Top, HPS, Black	100	9,500	43	8.42	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	9.65	
Cobrahead, Metal Halide	175	12,000	71	10.43	
Flood, Metal Halide	350	30,000	139	14.84	
Flood, Metal Halide	400	40,000	156	16.11	
Flood, HPS	750	105,000	285	27.35	(I)
HADCO Independence, HPS	100	9,500	43	11.44	(R)
	150	16,000	62	12.65	(I)
HADCO Capitol Acorn, HPS	100	9,500	43	14.89	
	150	16,000	62	14.83	(I)
	200	22,000	79	15.93	(R)
	250	29,000	102	17.38	(I)
HADCO Techtra, HPS	100	9,500	43	19.79	(R)
	150	16,000	62	20.78	(R)
	250	29,000	102	23.15	(I)
HADCO Westbrooke, HPS	70	6,300	30	13.01	(R)
	100	9,500	43	13.42	(R)
	150	16,000	62	19.18	(I)
	200	22,000	79	15.90	
	250	29,000	102	17.93	
Holophane Mongoose, HPS	150	16,000	62	12.89	(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	60	5,488	21	$ 12.40	(R)
	70	4,332	24	14.23	
HADCO LED	70	5,120	24	17.12	(R)
Cobrahead					
LED	37	2,530	13	4.11	(I)
	50	3,162	17	4.36	
	52	3,757	18	4.76	
	67	5,050	23	5.28	
	106	7,444	36	6.86	(I)
	134	14,200	46	9.32	
	156	16,300	53	10.89	(I)
	176	18,300	60	11.74	(I)
	201	21,400	69	11.62	(R)
Westbrooke LED (Non-Flare)	36	3,369	12	13.96	
	53	5,079	18	16.04	
	69	6,661	24	16.04	(R)
	85	8,153	29	17.37	(I)
	136	12,687	46	20.47	(R)
	206	18,159	70	21.72	
Westbrooke LED (Flare)	36	3,369	12	14.99	
	53	5,079	18	17.99	
	69	6,661	24	18.37	
	85	8,153	29	17.72	
	136	12,687	46	21.49	
	206	18,159	70	23.02	(R)
CREE XSP LED	25	2,529	9	3.01	(I)
	42	3,819	14	3.41	
	48	4,373	16	3.94	
	56	5,863	19	4.56	
	91	8,747	31	5.33	
Post-Top, American Revolution					
LED	45	3,395	15	7.00	
	72	4,409	25	7.11	(I)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$ 5.08	(R)
	40 to 55	6.63	
Wood, Painted Underground	35 or less	5.08 [2]	
Wood, Curved laminated	30 or less	6.28 [2]	
Aluminum, Regular	16	6.03	
	25	10.01	
	30	10.81	
	35	12.92	
Aluminum, Fluted Ornamental	14	8.81	
Aluminum Davit	25	9.99	
	30	9.95	
	35	10.87	
	40	14.73	
Aluminum Double Davit	30	14.64	
Aluminum, Fluted Ornamental	16	9.00	
Aluminum, HADCO, Smooth Techtra Ornamental	18	17.32	
Aluminum, HADCO, Fluted Westbrooke	18	17.36	
Aluminum, HADCO, Smooth Westbrooke	18	18.40	
Concrete, Ameron Post-Top	25	17.28	
Fiberglass Fluted Ornamental; Black	14	10.66	
Fiberglass, Regular			
Black	20	4.46	
Gray or Bronze	30	7.57	
Black, Gray, or Bronze	35	6.51	
Fiberglass, Anchor Base, Gray or Black	35	11.83	
Fiberglass, Direct Bury with Shroud	18	7.19	(R)

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

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 Point of Delivery (POD)*:

Basic Charge		
Single Phase	$18.00	(I)
Three Phase	$24.00	(I)
Distribution Charge		
First 5,000 kWh	4.357 ¢ per kWh	(I)
Over 5,000 kWh	0.782 ¢ 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.

Portland General Electric Company
P.U.C. Oregon No. E-18

Tenth Revision of Sheet No. 538-1
Canceling Ninth Revision of Sheet No. 538-1

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 voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2015.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$25.00		
Distribution Charge	7.416	¢ 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 Point of Delivery (POD)*:

<u>Basic Charge</u>		
Summer Months**	$40.00	
Winter Months**	No Charge	
<u>Distribution Charge</u>		
First 50 kWh per kW of Demand	8.442 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	6.442 ¢ 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 Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$3,350.00	$1,910.00	$4,080.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.65	$1.61	$1.61	
Over 4,000 kW	$1.34	$1.30	$1.30	
per kW of monthly On-Peak Demand**	$2.84	$2.76	$1.36	(I)
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	0.102 ¢	0.101 ¢	0.100 ¢	(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**	$0.111	$0.108	$0.053	(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.

Portland General Electric Company
P.U.C. Oregon No. E-18

Eleventh Revision of Sheet No. 583-1
Canceling Tenth Revision of Sheet No. 583-1

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 Point of Delivery (POD)*:

Basic Charge		
Single Phase Service	$30.00	
Three Phase Service	$40.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$3.84	(I)
Over 30 kW	$3.74	|
per kW of monthly On-Peak Demand	$2.84	(I)
System Usage Charge		
per kWh	0.527 ¢	(R)

* 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 POD.

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 Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$530.00	$490.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.50	$3.42	(I)
Over 200 kW	$2.60	$2.52	|
per kW of monthly On-Peak Demand	$2.84	$2.76	(I)
System Usage Charge			
per kWh	0.012 ¢	0.010 ¢	(R)

* 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 POD.

Portland General Electric Company
P.U.C. Oregon No. E-18

Thirteenth Revision of Sheet No. 589-1
Canceling Twelfth Revision of Sheet No. 589-1

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 Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,350.00	$1,910.00	$4,080.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.65	$1.61	$1.61	
Over 4,000 kW	$1.34	$1.30	$1.30	
per kW of monthly on-peak Demand	$2.84	$2.76	$1.36	(I)
System Usage Charge				
per kWh	0.102 ¢	0.101 ¢	0.100 ¢	(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 POD.

SCHEDULE 590
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW and Aggregate to >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

<u>Basic Charge</u>	$5,600.00	(R)
<u>Distribution Charges</u>**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.48	(I)
Over 4,000 kW	$1.17	
per kW of monthly on-peak Demand	$2.76	(I)
<u>System Usage Charge</u>		
per kWh	(0.042) ¢	(R)

* 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 POD.

SCHEDULE 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	6.374 ¢ per kWh	(I)
Energy Charge	Provided by Energy 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

Portland General Electric Company — Eighteenth Revision of Sheet No. 591-7
P.U.C. Oregon No. E-18 — Canceling Seventeenth Revision of Sheet No. 591-7

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$135.00 per hour	$193.00 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	*	$ 3.18	$ 1.91	(I)
	100	9,500	43	*	4.01	2.74	
	150	16,000	62	*	5.23	3.95	
	200	22,000	79	*	6.35	5.04	
	250	29,000	102	*	7.79	6.50	
	400	50,000	163	*	11.72	10.39	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.32	3.41	1.91	
	100	9,500	43	7.15	4.24	2.74	
	150	16,000	62	8.47	5.46	3.95	
	200	22,000	79	10.28	6.61	5.04	
	250	29,000	102	11.62	8.05	6.50	
	400	50,000	163	15.58	11.95	10.39	
Flood	250	29,000	102	11.90	8.08	6.50	
	400	50,000	163	15.79	11.97	10.39	
Early American Post-Top	100	9,500	43	7.53	4.29	2.74	
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	7.64	3.59	1.91	
	100	9,500	43	8.16	4.38	2.74	
	150	16,000	62	9.69	5.63	3.95	(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	$ 4.46	$ 0.14	(R)
Fiberglass, Black or Bronze	30	7.03	0.23	
Fiberglass, Gray	30	7.57	0.25	
Fiberglass, Smooth, Black or Bronze	18	4.46	0.14	
Fiberglass, Regular	18	3.98	0.13	
Black, Bronze, or Gray	35	6.51	0.21	
Wood, Standard	30 to 35	5.08	0.16	
Wood, Standard	40 to 55	6.63	0.22	(R)

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	$ 10.74	$ 4.68	$ 2.74	(I)	(I)	(I)
HADCO Victorian, HPS	150	16,000	62	11.95	5.89	3.95			
	200	22,000	79	13.71	7.07	5.04			
	250	29,000	102	15.17	8.53	6.50			
HADCO Capitol Acorn, HPS	100	9,500	43	14.34	5.15	2.74			
	150	16,000	62	14.28	6.19	3.95	(I)		
	200	22,000	79	15.38	7.29	5.04	(R)		
	250	29,000	102	16.83	8.74	6.50	(I)		
Special Architectural Types									
HADCO Independence, HPS	100	9,500	43	10.88	4.68	2.74	(R)		
	150	16,000	62	12.09	5.89	3.95	(I)		
HADCO Techtra, HPS	100	9,500	43	19.24	5.80	2.74	(R)		
	150	16,000	62	20.23	6.98	3.95	(R)		
	250	29,000	102	22.60	9.50	6.50	(I)		
HADCO Westbrooke, HPS	70	6,300	30	12.46	4.18	*	(R)		
	100	9,500	43	12.86	4.95	2.74	(R)	(I)	(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	$ 18.63	$ 6.76	$ 3.95	(I)
	200	22,000	79	15.34	7.28	5.04	
	250	29,000	102	17.37	8.81	6.50	
Special Types							
Flood, Metal Halide	350	30,000	139	14.29	10.60	8.86	
Flood, HPS	750	105,000	285	26.79	20.99	18.17	
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	4.08	
Ornamental Acorn	55	2,800	21	*	*	1.34	
Ornamental Acorn Twin	55	5,600	42	*	*	2.68	
Composite, Twin	140	6,815	54	*	*	3.44	
	175	9,815	66	*	*	4.21	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$ 10.01	$ 0.32	(R)
	30	10.81	0.35	
	35	12.92	0.42	
Aluminum Davit	25	9.99	0.32	
	30	9.95	0.32	
	35	10.87	0.35	
	40	14.73	0.48	
Aluminum Double Davit	30	14.64	0.47	
Aluminum, Fluted Ornamental	14	8.81	0.29	(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, HADCO, Smooth Techtra Ornamental	18	$ 17.32	$ 0.56	(R)
Aluminum, Fluted Ornamental	16	9.00	0.29	
Aluminum, HADCO, Fluted Westbrooke	18	17.36	0.56	
Aluminum, HADCO, Smooth Westbrooke	18	18.40	0.60	
Fiberglass, Fluted Ornamental Black	14	10.66	0.35	
Fiberglass, Anchor Base, Gray or Black	35	11.83	0.38	(R)

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	$ 8.76	$ 5.60	$ 3.82	(I)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.49	
	175	7,000	66	8.58	5.67	4.21	
	250	10,000	94	*	*	5.99	
	400	21,000	147	14.62	10.95	9.37	
	1,000	55,000	374	29.32	25.69	23.84	
Holophane Mongoose,	150	16,000	62	12.34	5.94	3.95	
HPS	250	29,000	102	14.34	8.42	*	(I)

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$ 7.28	*	*	
Mercury Vapor	175	7,000	66	9.54	$ 5.76	$ 4.21	(I)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	3.82	
	70	6,300	30	*	*	1.91	
	100	9,500	43	*	4.63	2.74	
	150	16,000	62	*	5.86	3.95	
	250	29,000	102	*	*	6.50	
	400	50,000	163	*	*	10.39	
Metal Halide	250	20,500	99	*	7.55	6.31	
	400	40,000	156	*	11.18	*	
Cobrahead, Metal Halide	175	12,000	71	*	6.18	4.53	
Flood, Metal Halide	400	40,000	156	15.56	11.74	9.94	
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	4.26	*	
100/150 Watt Ballast	100	9,500	43	*	4.26	*	
100/150 Watt Ballast	150	16,000	62	*	5.48	3.95	
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	6.33	3.95	
KIM Archetype, HPS	250	29,000	102	*	8.93	6.50	
	400	50,000	163	*	12.51	10.39	(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	$ 9.93	$ 3.87	*	(R)	(I)
Special GardCo Bronze Alloy								
HPS	70	5,000	30	*	*	$ 1.91		
Mercury Vapor	175	7,000	66	*	*	4.21		
Early American Post-Top, HPS								
Black	70	6,300	30	6.64	3.40	1.91		
Rectangle Type	200	22,000	79	*	*	5.04		
Incandescent	92	1,000	31	*	*	1.98		
	182	2,500	62	*	*	3.95		
Town and Country Post-Top								
Mercury Vapor	175	7,000	66	8.94	5.70	4.21		
Flood, HPS	70	6,300	30	6.23	3.32	*		
	100	9,500	43	7.05	4.25	2.74		
	200	22,000	79	10.49	6.67	5.04		
Cobrahead, HPS								
Power Door	310	37,000	124	13.38	9.81	7.90		
Special Types Customer-Owned & Maintained								
Ornamental, HPS	100	9,500	43	*	*	2.74		
Twin ornamental, HPS	Twin 100	9,500	86	*	*	5.48		
Compact Fluorescent	28	N/A	12	*	*	0.76		(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 6.03	*	(R)
Aluminum, Painted Ornamental	35	*	$ 0.96	
Aluminum, Regular	16	6.03	0.20	
Bronze Alloy GardCo	12	*	0.18	
Concrete, Ornamental	35 or less	10.01	0.32	
Fiberglass, Direct Bury with Shroud	18	7.19	0.23	
Steel, Painted Regular **	25	10.01	0.32	
Steel, Painted Regular **	30	10.81	0.35	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.32	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.32	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.35	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.35	
Wood, Laminated without Mast Arm	20	4.46	0.14	
Wood, Laminated Street Light Only	20	4.46	*	
Wood, Curved Laminated	30	6.28	0.23	
Wood, Painted Underground	35	5.08	0.16	(R)

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C			
Special Architectural Types Including Philips QL Induction Lamp Systems									
HADCO Victorian, QL	85	6,000	32	*	$ 2.74	$ 2.04		(I)	(I)
	165	12,000	60	*	4.65	3.82			
	165	12,000	60	$ 21.37	4.91	3.82	(R)	(I)	(I)

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Point of Delivery (POD)* is:

Distribution Charge	2.648 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 595 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	6.374 ¢ per kWh	(I)
Energy Charge	Provided by Energy Service Supplier	

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime [(1)]
	$135.00 per hour	$193.00 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 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 Rate Option A	
LED	37	2,530	13	$ 3.72	(I)
LED	50	3,162	17	3.97	|
LED	52	3,757	18	4.37	|
LED	67	5,050	23	5.01	|
LED	106	7,444	36	6.60	(I)
LED	134	14,200	46	9.72	(R)
LED	156	16,300	53	11.29	(I)
LED	176	18,300	60	12.14	(I)
LED	201	21,400	69	12.02	(R)

SCHEDULE 595 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$ 11.85	(R)
	70	4,332	24	13.68	
HADCO Acorn LED	70	5,120	24	17.53	
Westbrooke (Non-Flared)	36	3,369	12	14.37	
LED	53	5,079	18	15.49	
	69	6,661	24	15.49	(R)
	85	8,153	29	16.82	(I)
	136	12,687	46	19.92	(R)
	206	18,159	70	21.17	
Westbrooke (Flared)	36	3,369	12	15.39	
LED	53	5,079	18	17.43	
	69	6,661	24	17.81	
	85	8,153	29	17.16	
	136	12,687	46	20.93	
	206	18,159	70	22.46	(R)
Post-Top, American Revolution	45	3,395	15	7.40	(I)
LED	72	4,409	25	7.52	(I)

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.

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	0.333	¢ per kWh	Distribution Charge	(I)
15	0.551	¢ per kWh	Distribution Charge	(I)
32	0.302	¢ per kWh	Distribution Charge	(I)
38	0.354	¢ per kWh	Distribution Charge	(I)
47	0.518	¢ per kWh	Distribution Charge	(R)
49	0.380	¢ per kWh	Distribution Charge	(R)
75				
Secondary	0.170	¢ per kWh	System Usage Charge	(R)
Primary	0.167	¢ per kWh	System Usage Charge	(R)
Subtransmission	0.165	¢ 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	0.241	¢ per kWh	System Usage Charge	(I)
85				
Secondary	0.206	¢ per kWh	System Usage Charge	(R)
Primary	0.203	¢ per kWh	System Usage Charge	(I)
89				
Secondary	0.170	¢ per kWh	System Usage Charge	(R)
Primary	0.167	¢ per kWh	System Usage Charge	(R)
Subtransmission	0.165	¢ per kWh	System Usage Charge	(R)
90	0.158	¢ per kWh	System Usage Charge	(R)
91	0.555	¢ per kWh	Distribution Charge	(I)
92	0.211	¢ per kWh	Distribution Charge	(I)
95	0.555	¢ per kWh	Distribution Charge	(I)
485				
Secondary	0.067	¢ per kWh	System Usage Charge	(I)
Primary	0.067	¢ per kWh	System Usage Charge	(I)
489				
Secondary	0.041	¢ per kWh	System Usage Charge	(I)
Primary	0.040	¢ per kWh	System Usage Charge	(I)
Subtransmission	0.040	¢ per kWh	System Usage Charge	(I)
490	0.016	¢ per kWh	System Usage Charge	(I)
491	0.419	¢ per kWh	Distribution Charge	(I)
492	0.069	¢ per kWh	Distribution Charge	(I)
495	0.419	¢ per kWh	Distribution Charge	(I)

DO NOT BILL

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	0.415	¢ per kWh	Distribution Charge	(I)
532	0.137	¢ per kWh	Distribution Charge	(I)
538	0.201	¢ per kWh	Distribution Charge	(I)
549	0.191	¢ per kWh	Distribution Charge	(R)
575				
Secondary	0.041	¢ per kWh	System Usage Charge	(I)
Primary	0.040	¢ per kWh	System Usage Charge	(I)
Subtransmission	0.040	¢ per kWh	System Usage Charge	(I)
583	0.078	¢ per kWh	System Usage Charge	(I)
585				
Secondary	0.067	¢ per kWh	System Usage Charge	(I)
Primary	0.067	¢ per kWh	System Usage Charge	(I)
589				
Secondary	0.041	¢ per kWh	System Usage Charge	(I)
Primary	0.040	¢ per kWh	System Usage Charge	(I)
Subtransmission	0.040	¢ per kWh	System Usage Charge	(I)
590	0.016	¢ per kWh	System Usage Charge	(I)
591	0.419	¢ per kWh	Distribution Charge	(I)
592	0.069	¢ per kWh	Distribution Charge	(I)
595	0.419	¢ per kWh	Distribution Charge	(I)

DO NOT BILL

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' ELECTRIC BILLS BASE RATES
2018

CATEGORY	RATE SCHEDULE	Forecast SDEC16E18 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT w/ Sch. 125, 122, 146	TOTAL ELECTRIC BILLS PROPOSED w/ Sch. 125, 122, 146	Change AMOUNT	Change PCT.
Residential	7	772,009	7,559,949	$922,614,324	$987,892,759	$65,278,435	7.1%
Employee Discount				($978,490)	($1,047,016)	($68,526)	
Subtotal				$921,635,834	$986,845,742	$65,209,908	7.1%
Outdoor Area Lighting	15	0	16,416	$3,546,541	$3,616,193	$69,652	2.0%
General Service <30 kW	32	92,495	1,561,634	$175,760,185	$185,738,065	$9,977,879	5.7%
Opt. Time-of-Day G.S. >30 kW	38	384	30,166	$3,887,306	$4,201,942	$314,636	8.1%
Irrig. & Drain. Pump. < 30 kW	47	3,015	21,388	$4,169,616	$4,369,377	$199,761	4.8%
Irrig. & Drain. Pump. > 30 kW	49	1,320	65,471	$8,982,768	$9,797,883	$815,115	9.1%
General Service 31-200 kW	83	11,418	2,790,676	$254,210,801	$264,790,977	$10,580,175	4.2%
General Service 201-4,000 kW							
Secondary	85-S	1,243	2,263,250	$180,896,382	$187,607,889	$6,711,507	3.7%
Primary	85-P	189	617,288	$46,693,391	$48,056,707	$1,363,316	2.9%
Schedule 89 > 4 MW							
Primary	89-P	13	578,036	$38,375,426	$38,749,360	$373,934	1.0%
Subtransmission	89-T	4	59,270	$4,344,077	$4,480,527	$136,450	3.1%
Schedule 90	90-P	4	1,589,508	$96,922,777	$98,114,149	$1,191,372	1.2%
Street & Highway Lighting	91/95	203	50,700	$10,830,573	$11,063,020	$232,447	2.1%
Traffic Signals	92	17	2,907	$229,954	$240,361	$10,408	4.5%
COS TOTALS		882,314	17,206,660	$1,750,485,632	$1,847,672,192	$97,186,560	5.6%
Direct Access Service 201-4,000 kW							
Secondary	485-S	201	508,145	$11,103,278	$11,896,649	$793,370	
Primary	485-P	54	345,350	$8,019,976	$7,855,914	($164,062)	
Direct Access Service > 4 MW							
Secondary	489-S	1	12,514	$310,064	$378,866	$68,801	
Primary	489-P	12	757,775	$11,438,402	$13,194,866	$1,756,464	
Subtransmission	489-T	3	294,019	$1,861,615	$2,006,536	$144,921	
DIRECT ACCESS TOTALS		271	1,917,804	$32,733,335	$35,332,830	$2,599,496	
COS AND DA CYCLE TOTALS		882,585	19,124,464	$1,783,218,967	$1,883,005,022	$99,786,055	5.6%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 7

kWh	Net Monthly Bill: Current Prices	Net Monthly Bill: Proposed Prices	Percent Difference
50	$16.88	$18.39	8.9%
100	$22.13	$24.12	9.0%
200	$32.58	$35.53	9.1%
250	$37.82	$41.26	9.1%
300	$43.06	$46.97	9.1%
400	$53.52	$58.39	9.1%
500	$63.99	$69.82	9.1%
600	$74.43	$81.24	9.1%
700	$84.90	$92.65	9.1%
800	$95.37	$104.09	9.1%
820	$97.46	$106.37	9.1%
900	$105.83	$115.50	9.1%
1,000	$116.29	$126.94	9.2%
1,100	$128.51	$140.13	9.0%
1,200	$140.71	$153.29	8.9%
1,300	$152.95	$166.48	8.8%
1,400	$165.17	$179.66	8.8%
1,500	$177.40	$192.85	8.7%
1,600	$189.59	$206.01	8.7%
1,700	$201.81	$219.19	8.6%
1,800	$214.04	$232.38	8.6%
2,000	$238.46	$258.72	8.5%
2,300	$275.13	$298.26	8.4%
2,750	$330.10	$357.57	8.3%
3,000	$360.64	$390.51	8.3%
3,500	$421.75	$456.42	8.2%
4,000	$482.81	$522.29	8.2%
4,500	$543.92	$588.20	8.1%
5,000	$604.99	$654.08	8.1%
7,500	$910.45	$983.56	8.0%
10,000	$1,215.86	$1,313.00	8.0%

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	$71.42	$77.09	7.9%	$67.25	$72.92	8.4%
600	$82.38	$88.77	7.8%	$77.39	$83.77	8.2%
700	$93.39	$100.49	7.6%	$87.56	$94.66	8.1%
800	$104.37	$112.19	7.5%	$97.71	$105.53	8.0%
900	$115.36	$123.90	7.4%	$107.86	$116.40	7.9%
1,000	$126.34	$135.59	7.3%	$118.01	$127.26	7.8%
1,500	$181.28	$194.14	7.1%	$168.78	$181.64	7.6%
1,750	$208.75	$223.38	7.0%	$194.17	$208.79	7.5%
2,000	$236.21	$252.65	7.0%	$219.54	$235.98	7.5%
2,500	$291.14	$311.20	6.9%	$270.31	$290.36	7.4%
3,500	$401.01	$428.25	6.8%	$371.84	$399.08	7.3%
4,000	$455.93	$486.75	6.8%	$422.60	$453.42	7.3%
4,500	$510.87	$545.30	6.7%	$473.37	$507.80	7.3%
5,000	$565.80	$603.80	6.7%	$524.13	$562.14	7.3%
6,000	$646.47	$684.03	5.8%	$596.47	$634.04	6.3%
7,000	$727.14	$764.26	5.1%	$668.81	$705.93	5.6%
8,000	$807.81	$844.49	4.5%	$741.15	$777.83	4.9%
9,000	$888.49	$924.72	4.1%	$813.49	$849.73	4.5%
10,000	$969.16	$1,004.95	3.7%	$885.83	$921.63	4.0%
14,000	$1,291.85	$1,325.87	2.6%	$1,175.19	$1,209.21	2.9%
15,000	$1,372.52	$1,406.10	2.4%	$1,247.53	$1,281.11	2.7%
20,000	$1,775.89	$1,807.25	1.8%	$1,609.24	$1,640.60	1.9%
21,900	$1,929.16	$1,959.69	1.6%	$1,746.68	$1,777.21	1.7%

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	$77.60	$83.27	7.3%	$73.43	$79.10	7.7%
600	$88.56	$94.95	7.2%	$83.57	$89.95	7.6%
700	$99.57	$106.67	7.1%	$93.74	$100.84	7.6%
800	$110.55	$118.37	7.1%	$103.89	$111.71	7.5%
900	$121.54	$130.08	7.0%	$114.04	$122.58	7.5%
1,000	$132.52	$141.77	7.0%	$124.19	$133.44	7.4%
1,500	$187.46	$200.32	6.9%	$174.96	$187.82	7.4%
1,750	$214.93	$229.56	6.8%	$200.35	$214.97	7.3%
2,000	$242.39	$258.83	6.8%	$225.72	$242.16	7.3%
2,500	$297.32	$317.38	6.7%	$276.49	$296.54	7.3%
3,500	$407.19	$434.43	6.7%	$378.02	$405.26	7.2%
4,000	$462.11	$492.93	6.7%	$428.78	$459.60	7.2%
4,500	$517.05	$551.48	6.7%	$479.55	$513.98	7.2%
5,000	$571.98	$609.98	6.6%	$530.31	$568.32	7.2%
6,000	$652.65	$690.21	5.8%	$602.65	$640.22	6.2%
7,000	$733.32	$770.44	5.1%	$674.99	$712.11	5.5%
8,000	$813.99	$850.67	4.5%	$747.33	$784.01	4.9%
9,000	$894.67	$930.90	4.0%	$819.67	$855.91	4.4%
10,000	$975.34	$1,011.13	3.7%	$892.01	$927.81	4.0%
14,000	$1,298.03	$1,332.05	2.6%	$1,181.37	$1,215.39	2.9%
15,000	$1,378.70	$1,412.28	2.4%	$1,253.71	$1,287.29	2.7%
20,000	$1,782.07	$1,813.43	1.8%	$1,615.42	$1,646.78	1.9%
21,900	$1,935.34	$1,965.87	1.6%	$1,752.86	$1,783.39	1.7%

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	$45.65	$46.17	1.1%	$45.24	$45.76	1.1%
10	100	$55.24	$56.33	2.0%	$54.41	$55.49	2.0%
10	500	$132.03	$137.32	4.0%	$127.86	$133.15	4.1%
10	1,000	$217.68	$228.27	4.9%	$209.34	$219.93	5.1%
10	2,000	$389.00	$410.18	5.4%	$372.34	$393.52	5.7%
10	5,000	$902.98	$955.93	5.9%	$861.32	$914.26	6.1%
20	100	$55.24	$56.33	2.0%	$54.41	$55.49	2.0%
20	200	$74.45	$76.56	2.8%	$72.78	$74.89	2.9%
20	500	$132.03	$137.32	4.0%	$127.86	$133.15	4.1%
20	1,000	$227.98	$238.57	4.6%	$219.64	$230.23	4.8%
20	2,000	$399.30	$420.48	5.3%	$382.64	$403.82	5.5%
20	5,000	$913.28	$966.23	5.8%	$871.62	$924.56	6.1%
20	8,000	$1,427.27	$1,511.97	5.9%	$1,360.60	$1,445.31	6.2%
30	150	$64.86	$66.44	2.4%	$63.62	$65.19	2.5%
30	500	$132.03	$137.32	4.0%	$127.86	$133.15	4.1%
30	1,000	$227.98	$238.57	4.6%	$219.64	$230.23	4.8%
30	3,000	$580.93	$612.70	5.5%	$555.93	$587.70	5.7%
30	5,000	$923.58	$976.53	5.7%	$881.92	$934.86	6.0%
30	8,000	$1,437.57	$1,522.27	5.9%	$1,370.90	$1,455.61	6.2%
30	10,000	$1,780.22	$1,886.10	5.9%	$1,696.89	$1,802.78	6.2%
30	15,000	$2,636.85	$2,795.68	6.0%	$2,511.86	$2,670.69	6.3%

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	$772.07	$842.56	9.1%	$729.49	$799.98	9.7%
40%	35	10,220	$1,466.91	$1,607.86	9.6%	$1,381.75	$1,522.70	10.2%
60%	35	15,330	$2,161.73	$2,373.16	9.8%	$2,033.99	$2,245.42	10.4%
80%	35	20,440	$2,856.54	$3,138.46	9.9%	$2,686.22	$2,968.14	10.5%
20%	50	7,300	$1,085.32	$1,186.00	9.3%	$1,024.49	$1,125.17	9.8%
40%	50	14,600	$2,077.92	$2,279.28	9.7%	$1,956.27	$2,157.63	10.3%
60%	50	21,900	$3,070.55	$3,372.58	9.8%	$2,888.07	$3,190.10	10.5%
80%	50	29,200	$4,063.14	$4,465.86	9.9%	$3,819.82	$4,222.54	10.5%
20%	70	10,220	$1,502.98	$1,643.91	9.4%	$1,417.81	$1,558.75	9.9%
40%	70	20,440	$2,892.60	$3,174.51	9.7%	$2,722.28	$3,004.19	10.4%
60%	70	30,660	$4,282.27	$4,705.13	9.9%	$4,026.79	$4,449.65	10.5%
80%	70	40,880	$5,671.95	$6,235.72	9.9%	$5,331.31	$5,895.08	10.6%
20%	100	14,600	$2,129.42	$2,330.78	9.5%	$2,007.77	$2,209.13	10.0%
40%	100	29,200	$4,114.64	$4,517.36	9.8%	$3,871.32	$4,274.04	10.4%
60%	100	43,800	$6,099.88	$6,703.95	9.9%	$5,734.91	$6,338.98	10.5%
80%	100	58,400	$8,085.10	$8,890.53	10.0%	$7,598.46	$8,403.89	10.6%
20%	200	29,200	$4,217.64	$4,620.36	9.5%	$3,974.32	$4,377.04	10.1%
40%	200	58,400	$8,188.10	$8,993.53	9.8%	$7,701.46	$8,506.89	10.5%
60%	200	87,600	$12,158.54	$13,366.69	9.9%	$11,428.60	$12,636.75	10.6%
80%	200	116,800	$16,128.99	$17,739.86	10.0%	$15,155.74	$16,766.61	10.6%

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	$158.33	$169.83	7.3%	$149.99	$161.50	7.7%
3,000	$423.48	$457.99	8.1%	$398.48	$432.99	8.7%
5,000	$688.63	$746.15	8.4%	$646.97	$704.49	8.9%
7,000	$953.78	$1,034.32	8.4%	$895.45	$975.99	9.0%
10,000	$1,351.51	$1,466.56	8.5%	$1,268.18	$1,383.23	9.1%
13,000	$1,749.23	$1,898.80	8.6%	$1,640.91	$1,790.48	9.1%
14,000	$1,881.81	$2,042.88	8.6%	$1,765.15	$1,926.22	9.1%
16,000	$2,146.96	$2,331.04	8.6%	$2,013.64	$2,197.72	9.1%
21,000	$2,809.84	$3,051.45	8.6%	$2,634.85	$2,876.46	9.2%
25,000	$3,340.14	$3,627.77	8.6%	$3,131.83	$3,419.45	9.2%
30,000	$4,003.02	$4,348.17	8.6%	$3,753.04	$4,098.19	9.2%
35,000	$4,665.90	$5,068.58	8.6%	$4,374.26	$4,776.93	9.2%
40,000	$5,328.78	$5,788.98	8.6%	$4,995.47	$5,455.67	9.2%
45,000	$5,991.66	$6,509.39	8.6%	$5,616.69	$6,134.41	9.2%
50,000	$6,654.54	$7,229.80	8.6%	$6,237.90	$6,813.17	9.2%
75,000	$9,968.93	$10,831.81	8.7%	$9,343.98	$10,206.86	9.2%
100,000	$13,283.32	$14,433.83	8.7%	$12,450.05	$13,600.56	9.2%
150,000	$19,912.11	$21,637.88	8.7%	$18,662.20	$20,387.98	9.2%
200,000	$26,540.89	$28,841.91	8.7%	$24,874.35	$27,175.37	9.3%
300,000	$39,798.46	$43,249.99	8.7%	$37,298.65	$40,750.18	9.3%
400,000	$53,056.03	$57,658.07	8.7%	$49,722.95	$54,324.99	9.3%
500,000	$66,313.60	$72,066.15	8.7%	$62,147.25	$67,899.80	9.3%
750,000	$95,619.10	$104,247.94	9.0%	$89,369.58	$97,998.41	9.7%
1,000,000	$127,483.55	$138,988.65	9.0%	$119,150.85	$130,655.95	9.7%

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

Load Factor	kW	kWh	Net Monthly Billing (without RPA credit) Current Prices	Proposed Prices	Percent Difference	Net Monthly Bill (with RPA credit) Current Prices	Proposed Prices	Percent Difference
30%	30	6,570	$714.21	$756.18	5.9%	$659.46	$701.43	6.4%
30%	50	10,950	$1,160.82	$1,230.80	6.0%	$1,069.57	$1,139.55	6.5%
30%	75	16,425	$1,719.10	$1,824.02	6.1%	$1,582.23	$1,687.16	6.6%
30%	100	21,900	$2,277.36	$2,417.28	6.1%	$2,094.87	$2,234.80	6.7%
30%	135	29,565	$3,058.92	$3,247.82	6.2%	$2,812.56	$3,001.47	6.7%
30%	175	38,325	$3,952.14	$4,197.01	6.2%	$3,632.79	$3,877.66	6.7%
30%	200	43,800	$4,510.40	$4,790.25	6.2%	$4,145.43	$4,425.28	6.8%
50%	30	10,950	$1,042.99	$1,080.83	3.6%	$951.74	$989.58	4.0%
50%	50	18,250	$1,708.77	$1,771.82	3.7%	$1,556.70	$1,619.75	4.1%
50%	75	27,375	$2,541.02	$2,635.60	3.7%	$2,312.92	$2,407.49	4.1%
50%	100	36,500	$3,373.30	$3,499.39	3.7%	$3,069.15	$3,195.24	4.1%
50%	135	49,275	$4,538.42	$4,708.64	3.8%	$4,127.84	$4,298.05	4.1%
50%	175	63,875	$5,870.03	$6,090.70	3.8%	$5,337.78	$5,558.44	4.1%
50%	200	73,000	$6,702.26	$6,954.45	3.8%	$6,093.97	$6,346.16	4.1%
70%	30	15,330	$1,371.75	$1,405.45	2.5%	$1,244.01	$1,277.70	2.7%
70%	50	25,550	$2,256.76	$2,312.89	2.5%	$2,043.86	$2,099.99	2.7%
70%	75	38,325	$3,362.98	$3,447.17	2.5%	$3,043.63	$3,127.82	2.8%
70%	100	51,100	$4,469.21	$4,581.46	2.5%	$4,043.40	$4,155.66	2.8%
70%	135	68,985	$6,017.92	$6,169.46	2.5%	$5,443.09	$5,594.63	2.8%
70%	175	89,425	$7,787.91	$7,984.35	2.5%	$7,042.75	$7,239.19	2.8%
70%	200	102,200	$8,894.12	$9,118.64	2.5%	$8,042.52	$8,267.04	2.8%
90%	30	19,710	$1,700.56	$1,730.08	1.7%	$1,536.33	$1,565.85	1.9%
90%	50	32,850	$2,804.70	$2,853.93	1.8%	$2,530.97	$2,580.19	1.9%
90%	75	49,275	$4,184.93	$4,258.74	1.8%	$3,774.34	$3,848.15	2.0%
90%	100	65,700	$5,565.14	$5,663.56	1.8%	$5,017.68	$5,116.11	2.0%
90%	135	88,695	$7,497.43	$7,630.31	1.8%	$6,758.36	$6,891.24	2.0%
90%	175	114,975	$9,705.76	$9,878.01	1.8%	$8,747.71	$8,919.96	2.0%
90%	200	131,400	$11,085.97	$11,282.81	1.8%	$9,991.05	$10,187.89	2.0%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, Secondary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Net Monthly Bill

Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$4,551.43	$4,877.22	7.2%
30%	300	65,700	$6,518.12	$6,950.18	6.6%
30%	500	109,500	$10,451.54	$11,096.12	6.2%
30%	700	153,300	$14,384.95	$15,242.03	6.0%
30%	800	175,200	$16,351.63	$17,314.97	5.9%
30%	900	197,100	$18,318.35	$19,387.96	5.8%
30%	1,000	219,000	$20,285.05	$21,460.90	5.8%
30%	1,500	328,500	$30,118.59	$31,825.71	5.7%
30%	2,000	438,000	$39,952.09	$42,190.51	5.6%
30%	4,000	876,000	$76,564.19	$80,927.72	5.7%
50%	200	73,000	$6,466.42	$6,797.94	5.1%
50%	300	109,500	$9,390.64	$9,831.28	4.7%
50%	500	182,500	$15,239.06	$15,897.92	4.3%
50%	700	255,500	$21,087.46	$21,964.55	4.2%
50%	800	292,000	$24,011.66	$24,997.87	4.1%
50%	900	328,500	$26,935.89	$28,031.19	4.1%
50%	1,000	365,000	$29,860.08	$31,064.51	4.0%
50%	1,500	547,500	$44,481.13	$46,231.13	3.9%
50%	2,000	730,000	$59,102.15	$61,397.71	3.9%
50%	4,000	1,460,000	$112,819.65	$117,297.47	4.0%
70%	200	102,200	$8,381.40	$8,718.65	4.0%
70%	300	153,300	$12,263.15	$12,712.35	3.7%
70%	500	255,500	$20,026.56	$20,699.71	3.4%
70%	700	357,700	$27,789.98	$28,687.07	3.2%
70%	800	408,800	$31,671.70	$32,680.75	3.2%
70%	900	459,900	$35,553.41	$36,674.44	3.2%
70%	1,000	511,000	$39,435.11	$40,668.11	3.1%
70%	1,500	766,500	$56,461.92	$58,254.78	3.2%
70%	2,000	1,022,000	$75,065.55	$77,418.26	3.1%
70%	4,000	2,044,000	$149,013.10	$153,605.22	3.1%
90%	200	131,400	$10,296.43	$10,639.37	3.3%
90%	300	197,100	$15,135.65	$15,593.44	3.0%
90%	500	328,500	$24,814.09	$25,501.51	2.8%
90%	700	459,900	$34,492.51	$35,409.60	2.7%
90%	800	525,600	$39,331.72	$40,363.64	2.6%
90%	900	591,300	$44,170.94	$45,317.68	2.6%
90%	1,000	657,000	$49,010.14	$50,271.71	2.6%
90%	1,500	985,500	$70,143.97	$71,979.67	2.6%
90%	2,000	1,314,000	$93,162.28	$95,572.13	2.6%
90%	4,000	2,628,000	$185,206.56	$189,912.96	2.5%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Net Monthly Bill

Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$4,498.64	$4,746.62	5.5%
30%	300	65,700	$6,423.49	$6,774.87	5.5%
30%	500	109,500	$10,273.22	$10,831.38	5.4%
30%	700	153,300	$14,122.94	$14,887.88	5.4%
30%	800	175,200	$16,047.80	$16,916.13	5.4%
30%	900	197,100	$17,972.68	$18,944.40	5.4%
30%	1,000	219,000	$19,897.53	$20,972.64	5.4%
30%	1,500	328,500	$29,521.85	$31,113.92	5.4%
30%	2,000	438,000	$39,146.16	$41,255.19	5.4%
30%	4,000	876,000	$74,921.42	$79,098.28	5.6%
50%	200	73,000	$6,378.44	$6,632.44	4.0%
50%	300	109,500	$9,243.22	$9,603.62	3.9%
50%	500	182,500	$14,972.76	$15,545.96	3.8%
50%	700	255,500	$20,702.31	$21,488.30	3.8%
50%	800	292,000	$23,567.07	$24,459.46	3.8%
50%	900	328,500	$26,431.85	$27,430.64	3.8%
50%	1,000	365,000	$29,296.61	$30,401.80	3.8%
50%	1,500	547,500	$43,620.48	$45,257.66	3.8%
50%	2,000	730,000	$57,944.33	$60,113.51	3.7%
50%	4,000	1,460,000	$110,473.10	$114,770.26	3.9%
70%	200	102,200	$8,258.25	$8,518.26	3.1%
70%	300	153,300	$12,062.94	$12,432.36	3.1%
70%	500	255,500	$19,672.31	$20,260.54	3.0%
70%	700	357,700	$27,281.66	$28,088.72	3.0%
70%	800	408,800	$31,086.35	$32,002.81	2.9%
70%	900	459,900	$34,891.01	$35,916.88	2.9%
70%	1,000	511,000	$38,695.70	$39,830.97	2.9%
70%	1,500	766,500	$55,337.36	$57,019.65	3.0%
70%	2,000	1,022,000	$73,555.84	$75,785.17	3.0%
70%	4,000	2,044,000	$145,962.78	$150,380.24	3.0%
90%	200	131,400	$10,138.06	$10,404.10	2.6%
90%	300	197,100	$14,882.68	$15,261.12	2.5%
90%	500	328,500	$24,371.85	$24,975.12	2.5%
90%	700	459,900	$33,861.01	$34,689.12	2.4%
90%	800	525,600	$38,605.62	$39,546.14	2.4%
90%	900	591,300	$43,350.20	$44,403.13	2.4%
90%	1,000	657,000	$48,094.79	$49,260.13	2.4%
90%	1,500	985,500	$68,755.49	$70,482.90	2.5%
90%	2,000	1,314,000	$91,300.68	$93,590.16	2.5%
90%	4,000	2,628,000	$181,452.46	$185,990.23	2.5%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Secondary.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Net Monthly Bill

Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$73,430.39	$78,027.61	6.3%
30%	7,500	1,642,500	$135,026.52	$141,843.80	5.0%
30%	10,000	2,190,000	$178,979.43	$187,382.48	4.7%
30%	15,000	3,285,000	$266,885.30	$278,459.87	4.3%
30%	20,000	4,380,000	$354,791.16	$369,537.26	4.2%
50%	4,000	1,460,000	$108,921.92	$113,260.49	4.0%
50%	7,500	2,737,500	$201,456.88	$207,789.19	3.1%
50%	10,000	3,650,000	$267,553.25	$275,309.67	2.9%
50%	15,000	5,475,000	$399,746.03	$410,350.65	2.7%
50%	20,000	7,300,000	$531,938.80	$545,391.63	2.5%
70%	4,000	2,044,000	$144,351.45	$148,431.36	2.8%
70%	7,500	3,832,500	$267,887.25	$273,734.58	2.2%
70%	10,000	5,110,000	$356,127.07	$363,236.85	2.0%
70%	15,000	7,665,000	$532,606.76	$542,241.43	1.8%
70%	20,000	10,220,000	$709,086.44	$721,246.00	1.7%
90%	4,000	2,628,000	$179,780.98	$183,602.23	2.1%
90%	7,500	4,927,500	$334,317.61	$339,679.97	1.6%
90%	10,000	6,570,000	$444,700.89	$451,164.04	1.5%
90%	15,000	9,855,000	$665,467.49	$674,132.21	1.3%
90%	20,000	13,140,000	$886,234.08	$897,100.37	1.2%

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

Net Monthly Bill

Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$70,959.88	$75,011.19	5.7%
30%	7,500	1,642,500	$131,322.60	$137,485.82	4.7%
30%	10,000	2,190,000	$174,394.49	$182,066.24	4.4%
30%	15,000	3,285,000	$260,538.33	$271,227.11	4.1%
30%	20,000	4,380,000	$346,682.18	$360,387.97	4.0%
50%	4,000	1,460,000	$105,813.79	$109,606.46	3.6%
50%	7,500	2,737,500	$196,557.44	$202,235.69	2.9%
50%	10,000	3,650,000	$261,374.28	$268,399.40	2.7%
50%	15,000	5,475,000	$391,008.02	$400,726.84	2.5%
50%	20,000	7,300,000	$520,641.76	$533,054.29	2.4%
70%	4,000	2,044,000	$140,605.71	$144,139.72	2.5%
70%	7,500	3,832,500	$261,792.28	$266,985.56	2.0%
70%	10,000	5,110,000	$348,354.07	$354,732.55	1.8%
70%	15,000	7,665,000	$521,477.71	$530,226.58	1.7%
70%	20,000	10,220,000	$694,601.34	$705,720.61	1.6%
90%	4,000	2,628,000	$175,397.63	$178,672.98	1.9%
90%	7,500	4,927,500	$327,027.13	$331,735.42	1.4%
90%	10,000	6,570,000	$435,333.86	$441,065.71	1.3%
90%	15,000	9,855,000	$651,947.40	$659,726.32	1.2%
90%	20,000	13,140,000	$868,560.93	$878,386.92	1.1%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Transmission
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$67,247.22	$70,742.34	5.2%
30%	5,000	1,095,000	$83,241.60	$87,010.52	4.5%
30%	10,000	2,190,000	$162,903.50	$168,041.45	3.2%
30%	20,000	4,380,000	$322,227.30	$330,103.30	2.4%
30%	40,000	8,760,000	$640,874.90	$654,226.99	2.1%
30%	50,000	10,950,000	$800,198.70	$816,288.84	2.0%
30%	70,000	15,330,000	$1,118,846.29	$1,140,412.54	1.9%
50%	4,000	1,460,000	$101,637.97	$104,874.43	3.2%
50%	5,000	1,825,000	$126,152.53	$129,598.14	2.7%
50%	10,000	3,650,000	$248,725.37	$253,216.68	1.8%
50%	20,000	7,300,000	$493,871.03	$500,453.76	1.3%
50%	40,000	14,600,000	$984,162.36	$994,927.92	1.1%
50%	50,000	18,250,000	$1,229,308.03	$1,242,165.00	1.0%
50%	70,000	25,550,000	$1,719,599.36	$1,736,639.16	1.0%
70%	4,000	2,044,000	$135,966.71	$138,944.52	2.2%
70%	5,000	2,555,000	$169,063.47	$172,185.76	1.8%
70%	10,000	5,110,000	$334,547.23	$338,391.91	1.1%
70%	20,000	10,220,000	$665,514.76	$670,804.22	0.8%
70%	40,000	20,440,000	$1,327,449.82	$1,335,628.85	0.6%
70%	50,000	25,550,000	$1,658,417.36	$1,668,041.16	0.6%
70%	70,000	35,770,000	$2,320,352.42	$2,332,865.78	0.5%
90%	4,000	2,628,000	$170,295.46	$173,014.62	1.6%
90%	5,000	3,285,000	$211,974.40	$214,773.37	1.3%
90%	10,000	6,570,000	$420,369.10	$423,567.14	0.8%
90%	20,000	13,140,000	$837,158.49	$841,154.69	0.5%
90%	40,000	26,280,000	$1,670,737.29	$1,676,329.78	0.3%
90%	50,000	32,850,000	$2,087,526.69	$2,093,917.32	0.3%
90%	70,000	45,990,000	$2,921,105.48	$2,929,092.41	0.3%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 90, 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%	4,000	2,336,000	$175,718.66	$160,244.27	-8.8%
80%	5,000	2,920,000	$212,622.32	$198,419.03	-6.7%
80%	10,000	5,840,000	$397,140.64	$389,292.86	-2.0%
80%	20,000	11,680,000	$766,177.28	$771,040.53	0.6%
80%	40,000	23,360,000	$1,504,250.56	$1,534,535.86	2.0%
80%	60,000	35,040,000	$2,242,323.84	$2,298,031.18	2.5%
80%	80,000	46,720,000	$2,980,397.12	$3,061,526.51	2.7%
90%	4,000	2,628,000	$192,095.04	$176,957.50	-7.9%
90%	5,000	3,285,000	$233,092.80	$219,310.57	-5.9%
90%	10,000	6,570,000	$438,081.60	$431,075.95	-1.6%
90%	20,000	13,140,000	$848,059.19	$854,606.69	0.8%
90%	40,000	26,280,000	$1,668,014.38	$1,701,668.19	2.0%
90%	60,000	39,420,000	$2,487,969.57	$2,548,729.68	2.4%
90%	80,000	52,560,000	$3,307,924.76	$3,395,791.18	2.7%

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2018 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	$522,237	$25,137	$1,526	($5,526)	$21,137	$14,281	$2,327	$16,608	$36,466	$38,575	$71,581	$71,860	$218,482
Schedule 15	$842	$90	$2	($12)	$81	$17	$4	$21	$75	$80	$155	$110	$421
Schedule 32	$96,674	$4,720	$283	($1,141)	$3,861	$2,466	$431	$2,897	$5,623	$5,949	$13,685	$16,198	$41,455
Schedule 38	$1,727	$107	$5	($22)	$90	$38	$8	$46	$243	$257	$591	$645	$1,736
Schedule 47	$1,528	$111	$4	($16)	$100	$34	$7	$41	$238	$252	$579	$748	$1,816
Schedule 49	$4,643	$249	$14	($48)	$214	$103	$21	$124	$652	$690	$1,586	$1,154	$4,083
Schedule 83													
Secondary	$170,622	$6,738	$498	($2,040)	$5,197	$4,459	$761	$5,221	$10,590	$11,203	$25,746	$13,873	$61,412
Schedule 85													
Secondary		$5,015	$479	($2,026)	$3,468								
Primary		$1,480	$162	($704)	$939								
Class Total	$169,729					$4,322	$756	$5,078	$12,557	$13,283	$22,665	$10,004	$58,509
Schedule 89													
Secondary		$5	$2	($9)	($2)						$126		$126
Primary		$1,271	$212	($976)	$507						$3,146		$3,146
Subtransmission		$215	$55	($258)	$12						$852		$852
Class Total	$34,624					$986	$194	$1,180	$3,679	$4,981			$8,660
Schedule 90-P	$85,181	$2,507	$249	($1,162)	$1,594	$1,720	$338	$2,058	$3,641	$3,731	$1,639		$9,011
Schedules 91 & 95	$2,601	$282	$8	($37)	$252	$53	$12	$65	$233	$246	$479	$341	$1,299
Schedules 92	$155	$6	$0	($2)	$4	$3	$1	$4	$6	$6	$12	$4	$29
Totals	$1,090,564	$47,933	$3,500	($13,979)	$37,454	$28,484	$4,859	$33,343	$74,004	$79,252	$142,842	$114,937	$411,035

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2018 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	$107,727	$36	$6,420	$1	$5,335	$1	$55,547	$9	$36,317	$6	$211,345	$54		$211,399	$989,862
Schedule 15	$202		$57		$0		$117		$144		$520	$0	$1,685	$2,204	$3,569
Schedule 32	$12,659	$15,153	$210	$138	$964	$635	$3,338	$2,199	$3,354	$2,210	$20,525	$20,335		$40,860	$185,747
Schedule 38	$18	$324	$0	$0	$23	$143	$4	$27	$9	$56	$54	$550		$604	$4,202
Schedule 47	$23	$458	$0	$6	$4	$46	$13	$166	$12	$156	$52	$832		$885	$4,369
Schedule 49	$2	$399	$0	$5	$0	$27	$0	$79	$1	$221	$3	$730		$733	$9,798
Schedule 83															
Secondary	$393	$15,972	$6	$94	$42	$695	$48	$804	$242	$4,039	$731	$21,604		$22,334	$264,786
Schedule 85															
Secondary		$4,680		$26		$442		$224		$3,724	$0	$9,096		$9,096	
Primary		$696		$4		$74		$38		$627	$0	$1,440		$1,440	$248,260
Schedule 89															
Secondary		$20		$0		$0		$0		$20	$0	$40		$40	
Primary		$72		$0		$0		$4		$496	$0	$572		$572	
Subtransmission		$202		$0		$0		$1		$139	$0	$343		$343	$50,060
Schedule 90-P		$11		$0		$0		$0		$256	$0	$268		$268	$98,112
Schedules 91 & 95	$1,437			$0		$0	$356		$3		$1,796	$0	$5,097	$6,893	$11,110
Schedule 92		$17		$0		$0		$30		$0	$0	$47		$47	$240
Totals	$122,461	$38,043	$6,693	$275	$6,366	$2,062	$59,423	$3,581	$40,083	$11,950	$235,026	$55,911	$6,782	$297,719	$1,870,115

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2018

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 7						
Residential						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$211,345	771,879	Customers	$22.82	per cust. per mo.	$211,371
Three-Phase	$54	130	Customers	$34.32	per cust. per mo.	$54
Trans. & Rel. Serv. Charge	$16,608	7,559,949	MWh	2.20	mills/kWh	$16,632
Distribution Charge	$218,482	7,559,949	MWh	28.90	mills/kWh	$218,483
Franchise Fees & Other	$21,137	7,559,949	MWh	2.80	mills/kWh	$21,168
Energy Charge	$522,237	7,559,949	MWh	69.08	mills/kWh	$522,241
Subtotal	$989,862					$989,948
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		771,879	Customers	$11.50	per cust. per mo.	$106,519
Three-Phase		130	Customers	$11.50	per cust. per mo.	$18
Trans. & Rel. Serv. Charge		7,559,949	MWh	2.20	mills/kWh	$16,632
Distribution Charge		7,559,949	MWh	42.76	mills/kWh	$323,263
System Usage Charge Calculation						
Franchise Fees & Other		7,559,949	MWh	2.80	mills/kWh	$21,168
Cust Impact Offset		7,559,949	MWh	(0.26)	mills/kWh	($1,966)
System Usage Charge		7,559,949	MWh	2.54	mills/kWh	$19,202
Energy Charge						
Block 1 (First 500 kWh)		4,126,194	MWh	67.93	mills/kWh	$280,292
Block 2 (501-1,000 kWh)		2,226,625	MWh	67.93	mills/kWh	$151,255
Block 3 (Over 1,000 kWh)		1,207,130	MWh	75.15	mills/kWh	$90,716
Subtotal						$987,898
					w/o CIO	$989,863
SCHEDULE 15						
Outdoor Area Lighting						
Allocations						
Functional Costs						
Basic Charge	$520	9,439	Customers	$4.59	per cust. per mo.	$520
Trans. & Rel. Serv. Charge	$21	16,416	MWh	1.28	mills/kWh	$21
Distribution Charge	$421	16,416	MWh	25.62	mills/kWh	$421
Franchise Fees & Other	$81	16,416	MWh	4.93	mills/kWh	$81
Energy Charge	$842	16,416	MWh	51.29	mills/kWh	$842
Fixed Charges	$1,685	16,416	MWh			$1,685
Subtotal	$3,569					$3,569
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		16,416	MWh	1.28	mills/kWh	$21
Distribution Charge		16,416	MWh	57.29	mills/kWh	$940
System Usage Charge Calc						
Franchise Fees & Other		16,416	MWh	4.93	mills/kWh	$81
Cust Impact Offset		16,416	MWh	2.88	mills/kWh	$47
System Usage Charge		16,416	MWh	7.81	mills/kWh	$128
Energy Charge		16,416	MWh	51.29	mills/kWh	$842
Fixed Charges		16,416	MWh			$1,685
Subtotal						$3,616
					w/o CIO	$3,569

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2018

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 32						
General Service <30 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$20,525	55,761	Customers	$30.67	per cust. per mo.	$20,522
Three-Phase	$20,335	36,735	Customers	$46.13	per cust. per mo.	$20,335
Trans. & Rel. Serv. Charge	$2,897	1,561,634	MWh	1.85	mills/kWh	$2,889
Distribution Charge	$41,455	1,561,634	MWh	26.55	mills/kWh	$41,461
Franchise Fees & Other	$3,861	1,561,634	MWh	2.47	mills/kWh	$3,857
Energy Charge	$96,674	1,561,634	MWh	61.91	mills/kWh	$96,681
Subtotal	$185,747					$185,746
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		55,761	Customers	$18.00	per cust. per mo.	$12,044
Three-Phase		36,735	Customers	$24.00	per cust. per mo.	$10,580
Trans. & Rel. Serv. Charge		1,561,634	MWh	1.85	mills/kWh	$2,889
Distribution Charge						
First 5 MWh		1,363,981	MWh	42.75	mills/kWh	$58,310
Over 5 MWh		197,654	MWh	7.00	mills/kWh	$1,384
System Usage Charge Calc						
Franchise Fees & Other		1,561,634	MWh	2.47	mills/kWh	$3,857
Cust Impact Offset		1,561,634	MWh	0.00	mills/kWh	$0
System Usage Charge		1,561,634	MWh	2.47	mills/kWh	$3,857
Energy Charge		1,561,634	MWh	61.91	mills/kWh	$96,681
Subtotal						$185,745
					w/o CIO	$185,745
SCHEDULE 38						
Time-of-Day G.S. >30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$54	52	Customers	$86.11	per cust. per mo.	$54
Three-Phase	$550	332	Customers	$138.10	per cust. per mo.	$550
Trans. & Rel. Serv. Charge	$46	30,166	MWh	1.53	per cust. per mo.	$46
Distribution Charges	$1,736	30,166	MWh	57.53	per cust. per mo.	$1,735
Franchise Fees & Other	$90	30,166	MWh	2.97	mills/kWh	$90
Energy Charge	$1,727	30,166	MWh	57.24	mills/kWh	$1,727
Subtotal	$4,202					$4,202
Pricing						
Functional Costs						
Basic						
Single-Phase		52	Customers	$25.00	per cust. per mo.	$16
Three-Phase		332	Customers	$25.00	per cust. per mo.	$100
Trans. & Rel. Serv. Charge		30,166	MWh	1.53	mills/kWh	$46
Distribution Charges		30,166	MWh	72.71	mills/kWh	$2,193
System Usage Charge						
Franchise Fees & Other		30,166	MWh	2.97	mills/kWh	$90
Cust Impact Offset		30,166	MWh	0.00	mills/kWh	$0
System Usage Charge		30,166	MWh	2.97	mills/kWh	$90
Energy Charge Calc						
On-Peak (special)		16,672	MWh	61.71	mills/kWh	$1,029
Off-Peak		13,494	MWh	51.71	mills/kWh	$698
Reactive Demand Charge		61,814	kVar	0.50	kVar	$31
Subtotal						$4,202
					w/o CIO	$4,202

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2018

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 47						
Irrig. & Drain. Pump. - < 30 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$52	219	Customers	$39.78	per cust. per summ. mo.	$52
Three-Phase	$832	2,796	Customers	$49.61	per cust. per summ. mo.	$832
Trans. & Rel. Serv. Charge	$41	21,388	MWh	1.90	mills/kWh	$41
Distribution Charges	$1,816	21,388	MWh	84.93	mills/kWh	$1,816
Franchise Fees & Other	$100	21,388	MWh	4.66	mills/kWh	$100
Energy Charge	$1,528	21,388	MWh	71.46	mills/kWh	$1,528
Subtotal	$4,369					$4,370
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		219	Customers	$35.00	per cust. per summ. mo.	$46
Three-Phase		2,796	Customers	$35.00	per cust. per summ. mo.	$587
Trans. & Rel. Serv. Charge		21,388	MWh	1.90	mills/kWh	$41
Distribution Charge Calc						
First 50 kWh per kW		6,960	MWh	110.16	mills/kWh	$767
Over 50 kWh per kW		14,427	MWh	90.16	mills/kWh	$1,301
System Usage Charge Calc						
Franchise Fees & Other		21,388	MWh	4.66	mills/kWh	$100
Cust Impact Offset		21,388	MWh	0.00	mills/kWh	$0
System Usage Charge		21,388	MWh	4.66	mills/kWh	$100
Energy Charge		21,388	MWh	71.46	mills/kWh	$1,528
Reactive Demand Charge		71	kVar	$0.50	kVar	$0
Subtotal with Consumer Impact Offset						$4,369
					w/o CIO	$4,369
SCHEDULE 49						
Irrig. & Drain. Pump. - > 30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$3	6	Customers	$89.16	per cust. per summ. mo.	$3
Three-Phase	$730	1,314	Customers	$92.61	per cust. per summ. mo.	$730
Trans. & Rel. Serv. Charge	$124	65,471	MWh	1.90	mills/kWh	$124
Distribution Charges	$4,083	65,471	MWh	62.36	mills/kWh	$4,083
Franchise Fees & Other	$214	65,471	MWh	3.27	mills/kWh	$214
Energy Charge	$4,643	65,471	MWh	70.92	mills/kWh	$4,643
Subtotal	$9,798					$9,798
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		6	Customers	$40.00	per cust. per summ. mo.	$1
Three-Phase		1,314	Customers	$40.00	per cust. per summ. mo.	$315
Trans. & Rel. Serv. Charge		65,471	MWh	1.90	mills/kWh	$124
Distribution Charge Calc						
First 50 kWh per kW		18,464	MWh	83.04	mills/kWh	$1,533
Over 50 kWh per kW		47,007	MWh	63.04	mills/kWh	$2,963
System Usage Charge Calc						
Franchise Fees & Other		65,471	MWh	3.27	mills/kWh	$214
Cust Impact Offset		65,471	MWh	0.00	mills/kWh	$0
System Usage Charge		65,471	MWh	3.27	mills/kWh	$214
Energy Charge		65,471	MWh	70.92	mills/kWh	$4,643
Reactive Demand Charge		5,618	kVar	0.50	kVar	$3
Subtotal with Consumer Impact Offset						$9,798
					w/o CIO	$9,798

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2018

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 83						
General Service 31-200 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase Secondary	$731	646	Customers	$94.25	per cust, per mo.	$731
Three-Phase Secondary	$21,604	10,772	Customers	$167.13	per cust, per mo.	$21,603
Transmission & Related Service Charge	$5,221	8,365,029	kW demand	$0.62	per kW demand	$5,186
Distribution Charges						
Feeder Backbone	$25,746	10,484,996	kW faccap	$2.46	per kW faccap	$25,793
Feeder Local Facilities	$13,873	10,484,996	kW faccap	$1.32	per kW faccap	$13,840
Subtransmission Charge	$11,203	8,365,029	kW demand	$1.34	per kW demand	$11,209
Substation Charge	$10,590	8,365,029	kW demand	$1.27	per kW demand	$10,624
Secondary Franchise Fees & Other	$5,197	2,790,676	MWh	1.86	mills/kWh	$5,191
Secondary COS Energy Charge	$170,622	2,790,676	MWh	61.14	mills/kWh	$170,622
Subtotal	$264,786					$264,799
Pricing						
Functional Costs						
Basic Charge						
Secondary Single-Phase		646	Customers	$30.00	per cust, per mo.	$233
Secondary Three-Phase		10,772	Customers	$40.00	per cust, per mo.	$5,170
Trans. & Rel. Serv. Charge						
On-peak		8,362,265	kW demand	$0.70	per kW demand	$5,854
Off-peak		2,764	kW demand	$0.00	per kW demand	$0
Distribution Charges						
Secondary Facilities Charge						
First 30 kW		4,110,360	kW faccap	$3.84	<= 30 kW faccap	$15,784
Over 30 kW		6,374,636	kW faccap	$3.74	> 30 kW faccap	$23,841
Secondary Demand Charge						
On-peak		8,362,265	kW demand	$2.84	per kW demand	$23,749
Off-peak		2,764	kW demand	$0.00	per kW demand	$0
Secondary System Usage Charge Calc						
Franchise Fees & Other		2,790,676	MWh	1.86	mills/kWh	$5,191
Cust Impact Offset		2,790,676	MWh	0.00	mills/kWh	$0
Rate Design		2,790,676	MWh	5.04	mills/kWh	$14,065
System Usage Charge		2,790,676	MWh	6.90	mills/kWh	$19,256
COS Energy Charge						
On-peak		1,853,930	MWh	66.18	mills/kWh	$122,693
Off-peak		936,746	MWh	51.18	mills/kWh	$47,943
Reactive Demand Charge		538,567	kVar	$0.50	kVar	$269
Subtotal						$264,791
					w/o CIO	$264,791

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2018

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 85						
General Service 201-4,000 kW						
Allocations						
Functional Costs						
Basic Charge						
Secondary	$9,096	1,444	Customers	$525.12	per cust, per mo.	$9,096
Primary	$1,440	243	Customers	$493.59	per cust, per mo.	$1,440
Transmission & Related Service Charge	$5,078	7,458,268	kW on-peak	$0.68	per kW demand	$5,072
Distribution Charges						
Feeder Backbone	$22,665	10,836,544	kW faccap	$2.09	per kW faccap	$22,648
Feeder Local Facilities	$10,004	10,836,544	kW faccap	$0.92	per kW faccap	$9,970
Subtransmission Charge	$13,283	9,175,712	kW on-peak	$1.45	per kW on-peak demand	$13,305
Substation Charge	$12,557	9,175,712	kW on-peak	$1.37	per kW on-peak demand	$12,571
Secondary Franchise Fees & Other	$3,468	2,771,395	MWh	1.25	mills/kWh	$3,464
Primary Franchise Fees & Other	$939	962,639	MWh	0.98	mills/kWh	$943
COS Energy Charge	$169,729	2,880,538	MWh	58.92	mills/kWh	$169,721
Subtotal	$248,260					$248,230
Pricing						
Functional Costs						
Basic Charge						
Secondary		1,444	Customers	$530.00	per cust, per mo.	$9,181
Primary		243	Customers	$490.00	per cust, per mo.	$1,429
Secondary Trans. & Rel. Serv. Charge		5,932,156	kW on-peak	$0.70	per kW demand	$4,153
Primary Trans. & Rel. Serv. Charge		1,526,112	kW on-peak	$0.68	per kW demand	$1,038
Distribution Charges						
Secondary Facilities Charge						
First 200 kW		3,464,400	kW faccap	$3.50	per kW faccap	$12,125
Over 200 kW		4,760,092	kW faccap	$2.60	per kW faccap	$12,376
Primary Facilities Charge						
First 200 kW		583,400	kW faccap	$3.42	per kW faccap	$1,995
Over 200 kW		2,028,652	kW faccap	$2.52	per kW faccap	$5,112
Secondary Demand Charge		6,961,126	kW on-peak	$2.84	per kW demand	$19,770
Primary Demand Charge		2,214,586	kW on-peak	$2.76	per kW demand	$6,112
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		2,263,250	MWh	1.51	mills/kWh	$3,418
Cust Impact Offset		2,263,250	MWh	0.00	mills/kWh	$0
COS System Usage Charge		2,263,250	MWh	1.51	mills/kWh	$3,418
DA Franchise Fees & Other		508,145	MWh	0.12	mills/kWh	$61
Cust Impact Offset		508,145	MWh	0.00	mills/kWh	$0
DA System Usage Charge		508,145	MWh	0.12	mills/kWh	$61
Primary System Usage Charge Calc						
COS Franchise Fees & Other		617,288	MWh	1.46	mills/kWh	$901
Cust Impact Offset		617,288	MWh	0.00	mills/kWh	$0
COS System Usage Charge		617,288	MWh	1.46	mills/kWh	$901
DA Franchise Fees & Other		345,350	MWh	0.10	mills/kWh	$35
Cust Impact Offset		345,350	MWh	0.00	mills/kWh	$0
DA System Usage Charge		345,350	MWh	0.10	mills/kWh	$35
Secondary COS Energy Charge						
On-peak		1,482,720	MWh	64.41	mills/kWh	$95,502
Off-peak		780,530	MWh	49.41	mills/kWh	$38,566
Primary COS Energy Charge						
On-peak		389,869	MWh	63.32	mills/kWh	$24,687
Off-peak		227,419	MWh	48.32	mills/kWh	$10,989
Reactive Demand Charge		1,517,064	kVar	0.50	kVar	$759
Subtotal						$248,207
					w/o CIO	$248,207

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2018

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 89 GT 4,000 kW						
General Service						
Allocations						
Functional Costs						
Secondary Basic Charge	$40	1	Customers	$3,352.56	per cust, per mo.	$40
Primary Basic Charge	$572	25	Customers	$1,907.34	per cust, per mo.	$572
Subtransmission Basic Charge	$343	7	Customers	$4,078.73	per cust, per mo.	$343
Transmission & Related Service Charge	$1,180	1,348,022	kW on-peak	$0.88	per kW on-peak demand	$1,186
Distribution Charges						
Feeder Backbone	$4,123	3,591,117	kW faccap	$1.15	per kW faccap	$4,130
Feeder Local Facilities						$0
Subtransmission Demand Charge	$4,981	3,138,227	kW on-peak	$1.59	per kW on-peak demand	$4,990
Substation Demand Charge	$3,679	2,375,553	kW on-peak	$1.55	per kW on-peak demand	$3,682
Secondary Franchise Fees & Other	($2)	12,514	MWh	(0.16)	mills/kWh	($2)
Primary Franchise Fees & Other	$507	1,335,811	MWh	0.38	mills/kWh	$508
Subtransmission Franchise Fees & Other	$12	353,289	MWh	0.03	mills/kWh	$11
Energy Charge	$34,624	637,306	MWh	54.33	mills/kWh	$34,625
Subtotal	$50,060					$50,084
Pricing						
Functional Costs						
Secondary Basic Charge		1	Customers	$3,350.00	per cust, per mo.	$40
Primary Basic Charge		25	Customers	$1,910.00	per cust, per mo.	$573
Subtransmission Basic Charge		7	Customers	$4,080.00	per cust, per mo.	$343
Secondary Trans. & Rel. Serv. Charge		0	kW on-peak	$0.70	per kW on-peak demand	$0
Primary Trans. & Rel. Serv. Charge		1,100,231	kW on-peak	$0.68	per kW on-peak demand	$748
Subtransmission Trans. & Rel. Serv. Charge		247,791	kW on-peak	$0.67	per kW on-peak demand	$166
Distribution Charges						
Secondary Facilities Charge						
First 1,000 kW		12,000	kW faccap	$1.65	per kW faccap	$20
1,001-4,000 kW		36,000	kW faccap	$1.65	per kW faccap	$59
Greater than 4,000 kW		47,196	kW faccap	$1.34	per kW faccap	$63
Primary Facilities Charge						
First 1,000 kW		300,000	kW faccap	$1.61	per kW faccap	$483
1,001-4,000 kW		900,000	kW faccap	$1.61	per kW faccap	$1,449
Greater than 4,000 kW		1,462,461	kW faccap	$1.30	per kW faccap	$1,901
Subtransmission Facilities Charge						
First 1,000 kW		84,000	kW faccap	$1.61	per kW faccap	$135
1,001-4,000 kW		252,000	kW faccap	$1.61	per kW faccap	$406
Greater than 4,000 kW		497,460	kW faccap	$1.30	per kW faccap	$647
Secondary Demand Charge		41,672	kW on-peak	$2.84	per kW on-peak demand	$118
Primary Demand Charge		2,333,881	kW on-peak	$2.76	per kW on-peak demand	$6,442
Subtransmission Demand Charge		762,674	kW on-peak	$1.36	per kW on-peak demand	$1,037
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		0	MWh	1.14	mills/kWh	$0
Cust Impact Offset		0	MWh	1.18	mills/kWh	$0
COS System Usage Charge		0	MWh	2.32	mills/kWh	$0
DA Franchise Fees & Other		12,514	MWh	(0.16)	mills/kWh	($2)
Cust Impact Offset		12,514	MWh	1.18	mills/kWh	$15
DA System Usage Charge		12,514	MWh	1.02	mills/kWh	$13
Primary System Usage Charge Calc						
COS Franchise Fees & Other		578,036	MWh	1.10	mills/kWh	$636
Cust Impact Offset		578,036	MWh	1.18	mills/kWh	$682
COS System Usage Charge		578,036	MWh	2.28	mills/kWh	$1,318
DA Franchise Fees & Other		757,775	MWh	(0.17)	mills/kWh	($129)
Cust Impact Offset		757,775	MWh	1.18	mills/kWh	$894
DA System Usage Charge		757,775	MWh	1.01	mills/kWh	$765
Subtransmission System Usage Charge Calc						
COS Franchise Fees & Other		59,270	MWh	1.07	mills/kWh	$63
Cust Impact Offset		59,270	MWh	1.18	mills/kWh	$70
COS System Usage Charge		59,270	MWh	2.25	mills/kWh	$133
DA Franchise Fees & Other		294,019	MWh	(0.18)	mills/kWh	($53)
Cust Impact Offset		294,019	MWh	1.18	mills/kWh	$347
DA System Usage Charge		294,019	MWh	1.00	mills/kWh	$294
Secondary Energy Charge						
On-peak		0	MWh	61.55	mills/kWh	$0
Off-peak		0	MWh	46.55	mills/kWh	$0
Primary Energy Charge						
On-peak		338,180	MWh	60.54	mills/kWh	$20,473
Off-peak		239,856	MWh	45.54	mills/kWh	$10,923
Subtransmission Energy Charge						
On-peak		38,391	MWh	59.79	mills/kWh	$2,295
Off-peak		20,878	MWh	44.79	mills/kWh	$935
Reactive Demand Charge		520,929	kVar	0.50	kVar	$260
Subtotal						$52,041
					w/o CIO	$50,033

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2018

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 90						
Primary Voltage Service						
Allocations						
Functional Costs						
Primary Basic Charge	$268	4	Customers	$5,579.44	per cust, per mo.	$268
Transmission & Related Service Charge	$2,058	2,350,676	kW on-peak	$0.88	per kW on-peak demand	$2,069
Distribution Charges						
Feeder Backbone	$1,639	2,466,186	kW faccap	$0.66	per kW faccap	$1,628
Subtransmission Demand Charge	$3,731	2,350,676	kW on-peak	$1.59	per kW on-peak demand	$3,738
Substation Demand Charge	$3,641	2,350,676	kW on-peak	$1.55	per kW on-peak demand	$3,644
Primary Franchise Fees & Other	$1,594	1,589,508	MWh	1.00	mills/kWh	$1,590
Energy Charge	$85,181	1,589,508	MWh	53.59	mills/kWh	$85,182
Subtotal	$98,112					$98,116
Pricing						
Functional Costs						
Primary Basic Charge		4	Customers	$5,600.00	per cust, per mo.	$269
Primary Trans. & Rel. Serv. Charge		2,350,676	kW on-peak	$0.68	per kW on-peak demand	$1,598
Distribution Charges						
Primary Facilities Charge						
First 4,000 kW		192,000	kW faccap	$1.48	per kW faccap	$284
Over 4,000 kW		2,274,186	kW faccap	$1.17	per kW faccap	$2,661
Primary Demand Charge		2,350,676	kW on-peak	$2.76	per kW on-peak demand	$6,488
Primary System Usage Charge Calc						
COS Franchise Fees & Other		1,589,508	MWh	1.00	mills/kWh	$1,590
Cust Impact Offset		1,589,508	MWh	0.00	mills/kWh	$0
COS System Usage Charge		1,589,508	MWh	1.00	mills/kWh	$1,590
Primary Energy Charge						
On-peak		914,819	MWh	59.96	mills/kWh	$54,853
Off-peak		674,690	MWh	44.96	mills/kWh	$30,334
Reactive Demand Charge		75,984	kVar	$0.50	kVar	$38
						$98,114
					w/o CIO	$98,114

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2018

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULES 91 & 95						
Street & Highway Lighting						
Allocations						
Functional Costs						
Basic Charge	$1,796	203	Customers	$737.34	per cust, per mo.	$1,796
Trans. & Rel. Serv. Charge	$65	50,700	MWh	1.28	mills/kWh	$65
Distribution Charge	$1,299	50,700	MWh	25.62	mills/kWh	$1,299
Franchise Fees & Other	$252	50,700	MWh	4.97	mills/kWh	$252
COS Energy Charge	$2,601	50,700	MWh	51.29	mills/kWh	$2,600
Fixed Charges	$5,097					$5,097
Subtotal	$11,110					$11,110
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		50,700	MWh	1.28	mills/kWh	$65
Distribution Charge		50,700	MWh	61.06	mills/kWh	$3,096
System Usage Charge Calc						
Franchise Fees & Other		50,700	MWh	4.97	mills/kWh	$252
Cust Impact Offset		50,700	MWh	(0.93)	mills/kWh	($47)
System Usage Charge		50,700	MWh	4.04	mills/kWh	$205
COS Energy Charge		50,700	MWh	51.29	mills/kWh	$2,600
Fixed Charges		50,700	MWh			$5,097
Subtotal						$11,063
					w/o CIO	$11,110
SCHEDULE 92						
Traffic Signals						
Allocations						
Functional Costs						
Basic Charge	$47	17	Customers	$231.99	per cust, per mo.	$47
Trans. & Rel. Serv. Charge	$4	2,907	MWh	1.39	mills/kWh	$4
Distribution Charge	$29	2,907	MWh	10.09	mills/kWh	$29
Franchise Fees & Other	$4	2,907	MWh	1.53	mills/kWh	$4
COS Energy Charge	$155	2,907	MWh	53.39	mills/kWh	$155
Subtotal	$240					$240
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		2,907	MWh	1.39	mills/kWh	$4
Distribution Charge		2,907	MWh	26.37	mills/kWh	$77
System Usage Charge Calc						
Franchise Fees & Other		2,907	MWh	1.53	mills/kWh	$4
Cust Impact Offset		2,907	MWh	0.00	mills/kWh	$0
System Usage Charge		2,907	MWh	1.53	mills/kWh	$4
COS Energy Charge		2,907	MWh	53.39	mills/kWh	$155
Subtotal						$240
					w/o CIO	$240

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at Current Prices ($000)	2018 Allocated Costs ($000)	Percent Change	Impact Offset Amount	Impact Offset MWH	CIO mills/kWh	CIO Revenues
Schedule 7	7,559,949	$922,614	$989,862	7.3%		7,559,949	(0.26)	($1,966)
Schedule 15	16,416	$3,547	$3,569	0.6%			2.88	$47
Schedule 32	1,561,634	$175,760	$185,747	5.7%	$0	0	0.00	$0
Schedule 38	30,166	$3,887	$4,202	8.1%	$0	0	0.00	$0
Schedule 47	21,388	$4,170	$4,369	4.8%	$0	0	0.00	$0
Schedule 49	65,471	$8,983	$9,798	9.1%	$0	0	0.00	$0
Schedule 83	2,790,676	$254,211	$264,786	4.2%	$0	0	0.00	$0
Schedule 85	2,880,538	$246,713	$255,470	3.5%	$0	0	0.00	$0
Schedule 89	637,306	$56,330	$56,829	0.9%	$2,000	0	1.18	$752
Schedule 90	1,589,508	$96,923	$98,112	1.2%	$0	0	0.00	$0
Schedules 91 & 95	50,700	$10,831	$11,110	2.6%			(0.93)	($47)
Schedule 92	2,907	$230	$240	4.5%			0.00	$0
COS TOTALS	17,206,660							
Sch 485 Energy	853,496					0	0.00	$0
Sch 489 Energy	1,064,309					0	1.18	$1,256
Totals	19,124,464	$1,784,197	$1,884,094	5.6%	$2,000	7,559,949		$42

PORTLAND GENERAL ELECTRIC
2018 Test Period Functionalized Revenue Requirement

Function	Amount	Spread
PRODUCTION	$1,090,691	$1,090,691
TRANSMISSION	$28,486	$28,486
ANCILLARY	$4,859	$4,859
DISTRIBUTION	$635,813	$635,813
METERING	$8,430	$8,430
BILLING	$63,013	$63,013
CONSUMER	$52,039	$52,039
TOTALS	$1,883,332	$1,883,332
Schedule 129		($13,979)
Employee Discount		$990
Partial Requirements Transmission		$0
Partial Requirements Distribution		$0
Spread Total		$1,870,343

Note: Employee discount is allocated to distribution

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2018 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$737,105	$737,019
Net Variable Power Costs	$353,586	$353,545
Production Costs	$1,090,691	$1,090,564
Ancillary Services	$4,859	$4,859
Transmission		
Transmission	$28,486	
Partial Requirements Daily Demand	$0	
Transmission Costs	$28,486	$28,484
Distribution Services	$635,813	
Franchise	($47,939)	
Uncollectibles	($6,968)	
Trojan Decommissioning	($3,500)	
Partial Requirements Daily Demand	$0	
Employee Discount	$990	$990
Distribution Costs	$578,395	$578,321
Consumer Services		
Metering Services	$8,430	$8,429
Billing Services	$63,013	$63,005
Other Consumer Services	$52,039	$52,033
Franchise Fees	$47,939	$47,933
Uncollectibles	$6,968	$6,967
Trojan Decommissioning	$3,500	$3,500
Schedule 129	($13,979)	($13,979)
Totals	$1,870,343	$1,870,115
Net of employee discount	$1,869,354	$1,869,126
Net of Sch 129	$1,883,332	$1,883,104
Calendar MWH (COS & ESS)	19,126,928	
Cycle MWH (COS & ESS)	19,124,464	
Cycle/Cal Ratio	99.99%	
COS Calendar Energy MWH	17,208,117	
COS Cycle MWH	17,206,660	
Cycle/Cal Ratio	99.99%	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF GENERATION REVENUE REQUIREMENT TO COS CUSTOMERS
2018

Schedules	COS Calendar Energy	Marginal Energy Costs ($000)	Generation Capacity Allocation	Marginal Capacity Costs ($000)	Maginal Load Following Costs ($000)	Marginal Capacity & Energy Costs ($000)	Capacity & Energy Allocation Percent	Allocated Capacity & Energy Costs ($000)	Cycle Basis Costs ($000)
Schedule 7	7,560,800	$280,771	53.17%	$185,673	$8,937	$475,381	47.89%	$522,296	$522,237
Schedule 15	16,416	$555	0.07%	$228	($17)	$766	0.08%	$842	$842
Schedule 32	1,562,981	$57,329	8.58%	$29,955	$782	$88,066	8.87%	$96,758	$96,674
Schedule 38	30,134	$1,136	0.12%	$411	$23	$1,570	0.16%	$1,725	$1,727
Schedule 47	21,310	$773	0.17%	$602	$10	$1,386	0.14%	$1,523	$1,528
Schedule 49	65,555	$2,378	0.52%	$1,825	$28	$4,231	0.43%	$4,649	$4,643
Schedule 83	2,795,422	$102,934	14.68%	$51,265	$1,361	$155,560	15.67%	$170,912	$170,622
Schedule 85	2,879,674	$104,953	13.81%	$48,239	$1,245	$154,437	15.56%	$169,679	$169,729
Schedule 89	628,699	$22,232	2.51%	$8,763	$94	$31,088	3.13%	$34,156	$34,624
Schedule 90	1,593,580	$56,202	6.16%	$21,517	$9	$77,728	7.83%	$85,399	$85,181
Schedule 91/95	50,700	$1,713	0.20%	$705	($52)	$2,367	0.24%	$2,601	$2,601
Schedule 92	2,845	$102	0.01%	$36	($0)	$138	0.01%	$152	$155
TOTAL	17,208,117	$631,078	100.0%	$349,222	$12,420	$992,720	100.00%	$1,090,691	$1,090,564
Simple Cycle Proxy Plant $/kW				$105.32			**TARGET**	**$1,090,691**	
Projected Peak Load				3,316					
Marginal Capacity Costs ($000)				$349,222					

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	1,471.8	$86.31	$127,033	50.14%	$14,281
Schedule 15	1.8	$86.31	$154	0.06%	$17
Schedule 32	254.1	$86.31	$21,934	8.66%	$2,466
Schedule 38	4.0	$86.31	$342	0.14%	$38
Schedule 47	3.5	$86.31	$300	0.12%	$34
Schedule 49	10.7	$86.31	$920	0.36%	$103
Schedule 83	459.6	$86.31	$39,666	15.66%	$4,459
Schedule 85	445.4	$86.31	$38,447	15.17%	$4,322
Schedule 89	80.9	$86.31	$6,981	2.76%	$785
Schedule 90-P	198.0	$86.31	$17,089	6.74%	$1,921
Schedules 91/95	5.5	$86.31	$476	0.19%	$53
Schedule 92	0.3	$86.31	$30	0.01%	$3
Totals	2,935.6		$253,372		
Target				100.00%	$28,484
Unit Marginal Cost $/kW		**$86.31**			

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE REVENUE REQUIREMENT
2018

Schedules	Production Allocation Percent	Class Revenue Requirement
Schedule 7	47.89%	$2,327
Schedule 15	0.08%	$4
Schedule 32	8.87%	$431
Schedule 38	0.16%	$8
Schedule 47	0.14%	$7
Schedule 49	0.43%	$21
Schedule 83	15.67%	$761
Schedule 85	15.56%	$756
Schedule 89	3.13%	$152
Schedule 90-P	7.83%	$380
Schedules 91/95	0.24%	$12
Schedule 92	0.01%	$1
TOTAL	100.00%	$4,859
	TARGET	$4,859

PORTLAND GENERAL ELECTRIC
Applicable 2018 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	2,936	$149.89	$440,018
	SCHEDULE 2 - REACTIVE SUPPLY & VOLTAGE CONTROL		$/kW year	
2	12 CP kW Average	2,935,609	$0.461	$1,353,316
	SCHEDULE 3 - REGULATION & FREQUENCY RESPONSE		$/kW month	
3	Billing Determinant: Sum of Monthly Average 12 CP KW	35,227,310	$0.09	$3,066,009
	Charge: $6.695 per kW per month x .013			
4		**ANCILLARY SERVICES TOTAL**		$4,859,343

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2018

Schedules	Cycle Generation Revenues	Allocation Percent	Class Revenue Requirement
Schedule 7	$522,414,013	43.60%	$1,526
Schedule 15	$841,977	0.07%	$2
Schedule 32	$96,743,251	8.07%	$283
Schedule 38	$1,726,632	0.14%	$5
Schedule 47	$1,528,366	0.13%	$4
Schedule 49	$4,643,209	0.39%	$14
Schedule 83	$170,635,722	14.24%	$498
Schedule 85-S	$163,952,733	13.68%	$479
Schedule 89-S	$707,584	0.06%	$2
Schedule 85-P	$55,566,836	4.64%	$162
Schedule 89-P	$72,541,372	6.05%	$212
Schedule 89-T	$18,948,318	1.58%	$55
Schedule 90-P	$85,186,566	7.11%	$249
Schedule 91/95	$2,600,403	0.22%	$8
Schedule 92	$155,212	0.01%	$0
TOTAL	$1,198,192,195		$3,500
		TARGET	$3,500

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2018

Schedules	Distribution Allocations	Transmission Allocations	Generation Allocations	Schedule 129 Allocations	Subtotal Allocations	Distribution Fran. Fee Allocations	Transmission Fran. Fee Allocations	Generation Fran. Fee Allocations	Schedule 129 Fran. Fee Allocations	Total Fran. Fee Allocations
Schedule 7	$431,406	$16,608	$522,237		$970,251	$11,177	$430	$13,530		$25,137
Schedule 15	$2,627	$21	$842		$3,491	$68	$1	$22		$90
Schedule 32	$82,597	$2,897	$96,674		$182,169	$2,140	$75	$2,505		$4,720
Schedule 38	$2,345	$46	$1,727		$4,117	$61	$1	$45		$107
Schedule 47	$2,705	$41	$1,528		$4,274	$70	$1	$40		$111
Schedule 49	$4,830	$124	$4,643		$9,597	$125	$3	$120		$249
Schedule 83	$84,245	$5,221	$170,622		$260,087	$2,183	$135	$4,420		$6,738
Schedule 85	$69,686	$5,078	$169,729	$7,210	$251,703	$1,805	$132	$4,397	$161	$6,495
Schedule 89	$14,008	$1,180	$34,624	$6,769	$56,581	$363	$31	$897	$201	$1,492
Schedule 90-P	$9,527	$2,058	$85,181		$96,767	$247	$53	$2,207		$2,507
Schedules 91/95	$8,200	$65	$2,601		$10,866	$212	$2	$67		$282
Schedule 92	$77	$4	$155		$236	$2	$0	$4		$6
TOTALS	$712,254	$33,343	$1,090,564	$13,979	$1,850,139	$18,453	$864	$28,254	$362	$47,933

Franchise Fee Revenue Requirement **$47,933**

Schedules	Distribution MWh	Distribution mills/kWh	Transmission MWh	Transmission mills/kWh	Generation MWh	Generation mills/kWh	Schedule 129 MWh	Schedule 129 mills/kWh	Total COS mills/kWh	Total DA mills/kWh	Difference COS/DA mills/kWh
Schedule 7	7,559,949	1.48	7,559,949	0.06	7,559,949	1.79	0		3.33		
Schedule 15	16,416	4.15	16,416	0.03	16,416	1.33	0		5.51	4.15	1.36
Schedule 32	1,561,634	1.37	1,561,634	0.05	1,561,634	1.60	0		3.02	1.37	1.65
Schedule 38	30,166	2.01	30,166	0.04	30,166	1.48	0		3.54	2.01	1.52
Schedule 47	21,388	3.28	21,388	0.05	21,388	1.85	0		5.18		
Schedule 49	65,471	1.91	65,471	0.05	65,471	1.84	0		3.80	1.91	1.89
Schedule 83	2,790,676	0.78	2,790,676	0.05	2,790,676	1.58	0		2.41	0.78	1.63
Schedule 85-S	2,771,395	0.49	2,263,250	0.05	2,263,250	1.53	508,145	0.19	2.06	0.67	1.39
Schedule 89-S	12,514	0.22	0	0.05	0	1.44	12,514	0.19	1.70	0.41	1.30
Schedule 85-P	962,639	0.48	617,288	0.04	617,288	1.50	345,350	0.19	2.03	0.67	1.36
Schedule 89-P	1,335,811	0.21	578,036	0.05	578,036	1.41	757,775	0.19	1.67	0.40	1.27
Schedule 89-T	353,289	0.21	59,270	0.05	59,270	1.39	294,019	0.19	1.65	0.40	1.25
Schedule 90-P	1,589,508	0.16	1,589,508	0.03	1,589,508	1.39			1.58	0.16	1.42
Schedule 91/95	50,700	4.19	50,700	0.03	50,700	1.33	0		5.55	4.19	1.36
Schedule 92	2,907	0.69	2,907	0.04	2,907	1.38	0		2.11	0.69	1.42
TOTALS	19,124,464		17,206,660		17,206,660		1,917,804				

Revenues

Schedules	MWh	Fran. Fee mills/kWh	Fran. Fee Revenues
Schedule 7	7,559,949	3.33	$25,137
Schedule 15	16,416	5.51	$90
Schedule 32	1,561,634	3.02	$4,720
Schedule 38	30,166	3.54	$107
Schedule 47	21,388	5.18	$111
Schedule 49	65,471	3.80	$249
Schedule 83	2,790,676	2.41	$6,738
Schedule 85-S	2,263,250	2.06	$4,672
Schedule 485-S	508,145	0.67	$343
Schedule 89-S	0	1.70	$0
Schedule 489-S	12,514	0.41	$5
Schedule 85-P	617,288	2.03	$1,250
Schedule 485-P	345,350	0.67	$230
Schedule 89-P	578,036	1.67	$966
Schedule 489-P	757,775	0.40	$305
Schedule 89-T	59,270	1.65	$98
Schedule 489-T	294,019	0.40	$118
Schedule 90-P	1,589,508	1.58	$2,507
Schedule 91/95	50,700	5.55	$282
Schedule 92	2,907	2.11	$6
TOTALS	19,124,464		$47,933

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2018

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 85-S	2,771,395	39.4%	$0	0.00
Schedule 89-S	12,514	0.2%	$0	0.00
Schedule 85-P	962,639	13.7%	$0	0.00
Schedule 89-P	1,335,811	19.0%	$0	0.00
Schedule 90-P	1,589,508	22.6%	$0	0.00
Schedule 89-T	353,289	5.0%	$0	0.00
TOTAL	7,025,156	100.00%	$0	
		TARGET	$0	0.00

ALLOCATION OF TRANSITION ADJUSTMENT FOR POST 2013 VINTAGE CUSTOMERS

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 7	7,559,949	39.5%	($5,526)	(0.73)
Schedule 15	16,416	0.1%	($12)	(0.73)
Schedule 32	1,561,634	8.2%	($1,141)	(0.73)
Schedule 38	30,166	0.2%	($22)	(0.73)
Schedule 47	21,388	0.1%	($16)	(0.73)
Schedule 49	65,471	0.3%	($48)	(0.73)
Schedule 83	2,790,676	14.6%	($2,040)	(0.73)
Schedule 85-S	2,771,395	14.5%	($2,026)	(0.73)
Schedule 89-S	12,514	0.1%	($9)	(0.73)
Schedule 85-P	962,639	5.0%	($704)	(0.73)
Schedule 89	1,335,811	7.0%	($976)	(0.73)
Schedule 89-T	353,289	1.8%	($258)	(0.73)
Schedule 90-P	1,589,508	8.3%	($1,162)	(0.73)
Schedules 91/95	50,700	0.3%	($37)	(0.73)
Schedule 92	2,907	0.0%	($2)	(0.73)
TOTAL	19,124,464	100.00%	($13,979)	(0.73)
		TARGET	($13,979)	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF UNCOLLECTIBLES
2018

Grouping	Marginal Cost Allocation Percent	Class Revenue Requirement
Schedule 7		
Single Phase	92.14%	$6,420
Three Phase	0.02%	$1
Schedule 15		
Residential	0.47%	$33
Commercial	0.34%	$24
Schedule 32		
Single Phase	3.01%	$210
Three Phase	1.98%	$138
Schedule 38		
Single Phase	0.00%	$0
Three Phase	0.00%	$0
Schedule 47		
Single Phase	0.01%	$0
Three Phase	0.09%	$6
Schedule 49		
Single Phase	0.00%	$0
Three Phase	0.07%	$5
Schedule 83		
Single Phase	0.08%	$6
Three Phase	1.34%	$94
Schedule 85		
Secondary	0.37%	$26
Primary	0.06%	$4
Schedule 89		
Secondary	0.00%	$0
Primary	0.00%	$0
Subtransmission	0.00%	$0
Schedule 90-P	0.00%	$0
Schedules 91/95	0.00%	$0
Schedule 92	0.00%	$0
TOTAL	100.00%	$6,967
	TARGET	$6,967

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2018

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	771,879	Customers	$20.73	$16,001	$23,243
		Three-Phase Customers	130	Customers	$62.80	$8	$12
	Transformer & Service						
		Single-Phase Customers	771,879	Customers	$75.35	$58,161	$84,484
		Three-Phase Customers	130	Customers	$128.27	$17	$24
FACILITIES	Feeder Backbone						
		Single-Phase Customers	2,022,577	kW, rateclass peak	$24.36	$49,270	$71,569
		Three-Phase Customers	341	kW, rateclass peak	$24.36	$8	$12
	Feeder Local Facilities						
		Single-Phase Customers	3,087,517	Design Demand	$16.02	$49,462	$71,848
		Three-Phase Customers	520	Design Demand	$16.02	$8	$12
DEMAND	Subtransmission		2,052,250	kW, rateclass peak	$12.94	$26,556	$38,575
	Substation		2,022,918	kW, rateclass peak	$12.41	$25,104	$36,466
SUBTOTAL						$224,596	$326,244
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		9,603	Lights	$4.02	$39	$56
	Transformer & Service		9,603	Lights	$2.67	$26	$37
FACILITIES	Feeder Backbone		850	kW, rateclass peak	$25.56	$22	$32
	Feeder Local Facilities		850	Design Demand	$18.16	$15	$22
DEMAND	Subtransmission		862	kW, rateclass peak	$12.94	$11	$16
	Substation		850	kW, rateclass peak	$12.41	$11	$15
FIXED	Luminaires & Poles						$342
SUBTOTAL						$123	$521
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		11,216	Lights	$4.02	$45	$65
	Transformer & Service		11,216	Lights	$2.67	$30	$44
FACILITIES	Feeeder Backbone		3,331	kW, rateclass peak	$25.56	$85	$124
	Feeder Local Facilities		3,331	Design Demand	$18.16	$60	$88
DEMAND	Subtransmission		3,380	kW, rateclass peak	$12.94	$44	$64
	Substation		3,331	kW, rateclass peak	$12.41	$41	$60
FIXED	Luminaires & Poles						$1,342
SUBTOTAL						$306	$1,786
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$121
	Transformer & Service						$81
FACILITIES	Feeeder Backbone						$155
	Feeder Local Facilities						$110
DEMAND	Subtransmission						$80
	Substation						$75
FIXED	Luminaires & Poles						$1,685
SUBTOTAL							$2,307

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2018

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 32 Small Non-residential General Service							
CUSTOMER	Meters						
		Single-Phase Customers	55,761	Customers	$18.32	$1,022	$1,484
		Three-Phase Customers	36,735	Customers	$78.49	$2,883	$4,188
	Transformer & Service						
		Single-Phase Customers	55,761	Customers	$137.97	$7,693	$11,175
		Three-Phase Customers	36,735	Customers	$205.49	$7,549	$10,965
FACILITIES	Feeder Backbone						
		Single-Phase Customers	122,029	kW, rateclass peak	$30.20	$3,685	$5,353
		Three-Phase Customers	189,925	kW, rateclass peak	$30.20	$5,736	$8,332
	Feeder Local Facilities						
		Single-Phase Customers	278,803	Design Demand	$23.78	$6,630	$9,631
		Three-Phase Customers	433,472	Design Demand	$10.43	$4,521	$6,567
DEMAND	Subtransmission		316,477	kW, rateclass peak	$12.94	$4,095	$5,949
	Substation		311,954	kW, rateclass peak	$12.41	$3,871	$5,623
SUBTOTAL						$47,685	$69,267
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	52	Customers	$62.80	$3	$5
		Three-Phase Customers	332	Customers	$140.82	$47	$68
	Transformer & Service						
		Single-Phase Customers	52	Customers	$179.91	$9	$14
		Three-Phase Customers	332	Customers	$531.34	$176	$256
FACILITIES	Feeder Backbone						
		Single-Phase Customers	682	kW, rateclass peak	$30.17	$21	$30
		Three-Phase Customers	12,796	kW, rateclass peak	$30.17	$386	$561
	Feeder Local Facilities						
		Single-Phase Customers	2,414	Design Demand	$22.13	$53	$78
		Three-Phase Customers	36,843	Design Demand	$10.60	$391	$567
DEMAND	Subtransmission		13,674	kW, rateclass peak	$12.94	$177	$257
	Substation		13,478	kW, rateclass peak	$12.41	$167	$243
SUBTOTAL						$1,431	$2,078
Schedule 47 Irrigation & Drainage Service - < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	219	Customers	$62.43	$14	$20
		Three-Phase Customers	2,796	Customers	$93.35	$261	$379
	Transformer & Service						
		Single-Phase Customers	219	Customers	$9.79	$2	$3
		Three-Phase Customers	2,796	Customers	$19.47	$54	$79
FACILITIES	Feeder Backbone						
		Single-Phase Customers	500	kW, rateclass peak	$30.20	$15	$22
		Three-Phase Customers	12,697	kW, rateclass peak	$30.20	$383	$557
	Feeder Local Facilities						
		Single-Phase Customers	2,278	Design Demand	$23.78	$54	$79
		Three-Phase Customers	44,177	Design Demand	$10.43	$461	$669
DEMAND	Subtransmission		13,389	kW, rateclass peak	$12.94	$173	$252
	Substation		13,197	kW, rateclass peak	$12.41	$164	$238
SUBTOTAL						$1,582	$2,298

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2018

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 49 Irrigation & Drainage Service - > 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	6	Customers	$62.80	$0	$1
		Three-Phase Customers	1,314	Customers	$77.06	$101	$147
	Transformer & Service						
		Single-Phase Customers	6	Customers	$131.88	$1	$1
		Three-Phase Customers	1,314	Customers	$131.88	$173	$252
FACILITIES	Feeder Backbone						
		Single-Phase Customers	164	kW, rateclass peak	$30.17	$5	$7
		Three-Phase Customers	36,024	kW, rateclass peak	$30.17	$1,087	$1,579
	Feeder Local Facilities						
		Single-Phase Customers	224	Design Demand	$22.13	$5	$7
		Three-Phase Customers	74,504	Design Demand	$10.60	$790	$1,147
DEMAND	Subtransmission		36,713	kW, rateclass peak	$12.94	$475	$690
	Substation		36,188	kW, rateclass peak	$12.41	$449	$652
SUBTOTAL						$3,086	$4,483
Schedule 83 General Service (31-200 kW)							
CUSTOMER	Meters						
		Single-Phase Customers	646	Customers	$62.43	$40	$59
		Three-Phase Customers	10,772	Customers	$139.36	$1,501	$2,181
	Transformer & Service						
		Single-Phase Customers	646	Customers	$356.24	$230	$334
		Three-Phase Customers	10,772	Customers	$881.44	$9,495	$13,792
FACILITIES	Feeder Backbone						
		Single-Phase Customers	16,810	kW, rateclass peak	$30.17	$507	$737
		Three-Phase Customers	570,674	kW, rateclass peak	$30.17	$17,217	$25,009
	Feeder Local Facilities						
		Single-Phase Customers	24,997	Design Demand	$22.13	$553	$804
		Three-Phase Customers	848,814	Design Demand	$10.60	$8,997	$13,069
DEMAND	Subtransmission		596,002	kW, rateclass peak	$12.94	$7,712	$11,203
	Substation		587,484	kW, rateclass peak	$12.41	$7,291	$10,590
SUBTOTAL						$53,544	$77,777
Schedule 85 General Service (201-4,000 kW)							
CUSTOMER	Meters						
		Secondary Customers	1,444	Customers	$175.18	$253	$367
		Primary Customers	243	Customers	$1,971.73	$479	$696
	Transformer & Service						
		Secondary Customers	1,444	Customers	$2,057.03	$2,969	$4,313
		Primary Customers	243	Customers	$0.00	$0	$0
FACILITIES	Feeder Backbone		696,577	kW, rateclass peak	$22.40	$15,603	$22,665
	Feeder Local Facilities		907,382	Design Demand	$7.59	$6,887	$10,004
DEMAND	Subtransmission		706,678	kW, rateclass peak	$12.94	$9,144	$13,283
	Substation		696,577	kW, rateclass peak	$12.41	$8,645	$12,557
SUBTOTAL						$43,981	$63,886

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2018

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 89 General Service (4,000 plus kW)							
CUSTOMER	Meters						
		Secondary Meters	1	Customers	$190.01	$0	$0
		Primary Meters	25	Customers	$1,975.66	$49	$72
		Substation Meters	7	Customers	$19,913.86	$139	$202
	Transformer & Service						
		Secondary Customers	1	Customers	$13,724.84	$14	$20
		Primary Customers	25	Customers	$0.00	$0	$0
FACILITIES	Feeder Backbone						
		Secondary Customers	1	Customers	$86,625.00	$87	$126
		Primary Customers	25	Customers	$86,625.00	$2,166	$3,146
		Subtransmission 115 kV Feeder	7	Customers	$83,765.00	$586	$852
DEMAND	Subtransmission		250,035	kW, rateclass peak	$12.94	$3,235	$4,700
	Substation (Sec. & Prim. Only)		195,636	kW, rateclass peak	$12.41	$2,428	$3,527
SUBTOTAL						$8,705	$12,644
Schedule 90 Primary Voltage Service							
CUSTOMER	Meters						
		Primary Meters	4	Customers	$1,971.73	$8	$11
FACILITIES	Feeder Backbone						
		Primary Customers	4	Customers	$282,102.00	$1,128	$1,639
DEMAND	Subtransmission		213,463	kW, rateclass peak	$12.94	$2,762	$4,012
	Substation (Sec. & Prim. Only)		210,412	kW, rateclass peak	$12.41	$2,611	$3,793
SUBTOTAL						$6,510	$9,456

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2018

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedules 91 & 95 Streetlighting & Highway Lighting						
CUSTOMER	Customer Service	148,015	Lights	$4.02	$594	$863
	Transformer & Service	148,015	Lights	$2.67	$395	$574
FACILITIES	Feeder Backbone	12,914	kW, rateclass peak	$25.56	$330	$479
	Feeder Local Facilities	12,914	Design Demand	$18.16	$235	$341
DEMAND	Subtransmission	13,101	kW, rateclass peak	$12.94	$170	$246
	Substation	12,914	kW, rateclass peak	$12.41	$160	$233
FIXED	Luminaires & Poles					$5,097
SUBTOTAL					$1,884	$7,834
Schedule 92 Traffic Signals						
CUSTOMER	Transformer & Service	1,359	Intersections	$8.79	$12	$17
FACILITIES	Feeder Backbone	335	kW, rateclass peak	$25.56	$9	$12
	Feeder Local Facilities	335	Design Demand	$9.17	$3	$4
DEMAND	Subtransmission	340	kW, rateclass peak	$12.94	$4	$6
	Substation	335	kW, rateclass peak	$12.41	$4	$6
SUBTOTAL					$32	$47
Summary						
CUSTOMER	Meters	882,365	Customers		$22,811	$33,135
	Transformer & Service		Customers		$87,007	$126,384
	Customer Service	168,834	Lights		$678	$985
FACILITIES	Feeder Backbone	3,699,226	kW, rateclass peak		$98,337	$142,842
	Feeder Local Facilities	5,759,375	Design Demand		$79,126	$114,937
DEMAND	Subtransmission	4,216,364	kW, rateclass peak		$54,560	$79,252
	Substation	4,105,274	kW rateclass peak		$50,946	$74,004
FIXED	Luminaires & Poles					$6,782
TOTALS					$393,464	$578,321
					TARGET	$578,321
				EQUAL PERCENT		145.3%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2018

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	771,879	$0.30	$232	$5,335
Three Phase	130	$0.30	$0	$1
Schedule 15				
Residential	5,463	$0.00	$0	$0
Commercial	3,976	$0.00	$0	$0
Schedule 32				
Single Phase	55,761	$0.75	$42	$964
Three Phase	36,735	$0.75	$28	$635
Schedule 38				
Single Phase	52	$18.71	$1	$23
Three Phase	332	$18.71	$6	$143
Schedule 47				
Single Phase	219	$0.71	$0	$4
Three Phase	2,796	$0.71	$2	$46
Schedule 49				
Single Phase	6	$0.88	$0	$0
Three Phase	1,314	$0.88	$1	$27
Schedule 83				
Single Phase	646	$2.80	$2	$42
Three Phase	10,772	$2.80	$30	$695
Schedule 85				
Secondary	1,444	$13.28	$19	$442
Primary	243	$13.28	$3	$74
Schedule 89				
Secondary	1	$0.55	$0	$0
Primary	25	$0.55	$0	$0
Subtransmission	7	$0.55	$0	$0
Schedule 90-P	4	$0.21	$0	$0
Schedules 91/95	203	$0.00	$0	$0
Schedule 92	17	$0.00	$0	$0
TOTAL	892,024		$366	$8,429
			TARGET	$8,429
		EQUAL PERCENT		2304%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2018

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	771,879	$38.50	$29,717	$55,547
Three Phase	130	$38.50	$5	$9
Schedule 15				
Residential	5,463	$5.93	$32	$61
Commercial	3,976	$7.58	$30	$56
Schedule 32				
Single Phase	55,761	$32.03	$1,786	$3,338
Three Phase	36,735	$32.03	$1,177	$2,199
Schedule 38				
Single Phase	52	$42.80	$2	$4
Three Phase	332	$42.80	$14	$27
Schedule 47				
Single Phase	219	$31.75	$7	$13
Three Phase	2,796	$31.75	$89	$166
Schedule 49				
Single Phase	6	$32.16	$0	$0
Three Phase	1,314	$32.16	$42	$79
Schedule 83				
Single Phase	646	$39.95	$26	$48
Three Phase	10,772	$39.95	$430	$804
Schedule 85				
Secondary	1,444	$82.87	$120	$224
Primary	243	$82.87	$20	$38
Schedule 89				
Secondary	1	$91.84	$0	$0
Primary	25	$91.84	$2	$4
Subtransmission	7	$91.84	$1	$1
Schedule 90-P	4	$16.76	$0	$0
Schedules 91/95	203	$937.38	$190	$356
Schedule 92	17	$935.16	$16	$30
TOTAL	892,024		$33,707	$63,005
			TARGET	$63,005
		EQUAL PERCENT		187%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2018

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	771,879	$20.36	$15,715	$36,317
Three Phase	130	$20.36	$3	$6
Schedule 15				
Residential	5,463	$6.60	$36	$83
Commercial	3,976	$6.60	$26	$61
Schedule 32				
Single Phase	55,761	$26.03	$1,451	$3,354
Three Phase	36,735	$26.03	$956	$2,210
Schedule 38				
Single Phase	52	$73.45	$4	$9
Three Phase	332	$73.45	$24	$56
Schedule 47				
Single Phase	219	$24.15	$5	$12
Three Phase	2,796	$24.15	$68	$156
Schedule 49				
Single Phase	6	$72.62	$0	$1
Three Phase	1,314	$72.62	$95	$221
Schedule 83				
Single Phase	646	$162.24	$105	$242
Three Phase	10,772	$162.24	$1,748	$4,039
Schedule 85				
Secondary	1,444	$1,116.48	$1,612	$3,724
Primary	243	$1,116.48	$271	$627
Schedule 89				
Secondary	1	$8,582.64	$9	$20
Primary	25	$8,582.64	$215	$496
Subtransmission	7	$8,582.64	$60	$139
Schedule 90-P	4	$27,717.39	$111	$256
Schedule 91/95	203	$6.60	$1	$3
Schedule 92	17	$6.60	$0	$0
TOTAL	892,024		$22,516	$52,033
			TARGET	$52,033
		EQUAL PERCENT		231%

PORTLAND GENERAL ELECTRIC

PROPOSED
Summary of Area and Streetlighting Revenue

Schedule 15 - Area Lighting	
Fixtures & Maintenance	$1,074,110
Poles	$610,413
Energy (volumetric c/kWh rate)	$1,931,749
Total	**$3,616,272**

Schedule 91/95 - Street and Highway Lighting	
Fixtures & Maintenance (Options A&B)	$2,674,926
Poles (Options A&B)	$2,422,224
Energy (volumetric c/kWh rate)	$5,966,787
Total	**$11,063,938**

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum CODE	Light Description	Type	Watts	Monthly kWh	Category	Tariff Rates A	Tariff Rates B	Monthly Energy	DAX Sch 91 & 95 A & B RATES A	B	C	TOTAL	Proposed Sch 91 & 95 A & B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	B
79	Cobrahead - PD	HPS	70-watt	30	Standard	$0.00	$1.27	$3.53	$0.00	$3.18	$1.91		-	-	-	0	30	$0	$0
84	Cobrahead - PD	HPS	100-watt	43	Standard	$0.00	$1.27	$5.06	$0.00	$4.01	$2.74		-	-	57	57	43	$0	$0
85	Cobrahead - PD	HPS	150-watt	62	Standard	$0.00	$1.28	$7.30	$0.00	$5.23	$3.95		-	-	67	67	62	$0	$0
89	Cobrahead - PD	HPS	200-watt	79	Standard	$0.00	$1.31	$9.30	$0.00	$6.35	$5.04		-	-	118	118	79	$0	$0
86	Cobrahead - PD	HPS	250-watt	102	Standard	$0.00	$1.29	$12.00	$0.00	$7.79	$6.50		-	-	105	105	102	$0	$0
87	Cobrahead - PD	HPS	400-watt	163	Standard	$0.00	$1.33	$19.18	$0.00	$11.72	$10.39		-	-	21	21	163	$0	$0
33	Cobrahead	HPS	70-watt	30	Standard	$4.41	$1.50	$3.53	$6.32	$3.41	$1.91		19	162	150	331	30	$1,005	$2,916
34	Cobrahead	HPS	100-watt	43	Standard	$4.41	$1.50	$5.06	$7.15	$4.24	$2.74		501	3,653	123	4,277	43	$26,513	$65,754
35	Cobrahead	HPS	150-watt	62	Standard	$4.52	$1.51	$7.30	$8.47	$5.46	$3.95		12	872	161	1,045	62	$651	$15,801
39	Cobrahead	HPS	200-watt	79	Standard	$5.24	$1.57	$9.30	$10.28	$6.61	$5.04		124	2,708	261	3,093	79	$7,797	$51,019
36	Cobrahead	HPS	250-watt	102	Standard	$5.12	$1.55	$12.00	$11.62	$8.05	$6.50		27	1,112	278	1,417	102	$1,659	$20,683
37	Cobrahead	HPS	400-watt	163	Standard	$5.19	$1.56	$19.18	$15.58	$11.95	$10.39		723	186	106	1,015	163	$45,028	$3,482
31	Flood	HPS	250-watt	102	Standard	$5.40	$1.58	$12.00	$11.90	$8.08	$6.50		126	2	-	128	102	$8,165	$38
32	Flood	HPS	400-watt	163	Standard	$5.40	$1.58	$19.18	$15.79	$11.97	$10.39		295	12	2	309	163	$19,116	$228
40	Post-Top	HPS	100-watt	43	Standard	$4.79	$1.55	$5.06	$7.53	$4.29	$2.74		4,724	3,931	243	8,898	43	$271,536	$73,117
76	Shoebox	HPS	70-watt	30	Standard	$5.73	$1.68	$3.53	$7.64	$3.59	$1.91		1	67	8	76	30	$69	$1,351
77	Shoebox	HPS	100-watt	43	Standard	$5.42	$1.64	$5.06	$8.16	$4.38	$2.74		7	4,122	1,334	5,463	43	$455	$81,121
78	Shoebox	HPS	150-watt	62	Standard	$5.74	$1.68	$7.30	$9.69	$5.63	$3.95		1	270	119	390	62	$69	$5,443
81	Special Acorn	HPS	100-watt	43	Custom	$8.00	$1.94	$5.06	$10.74	$4.68	$2.74		725	3,480	364	4,569	43	$69,600	$81,014
82	Victorian	HPS	150-watt	62	Custom	$8.00	$1.94	$7.30	$11.95	$5.89	$3.95		82	1,230	185	1,497	62	$7,872	$28,634
49	Victorian	HPS	200-watt	79	Custom	$8.67	$2.03	$9.30	$13.71	$7.07	$5.04		3	197	-	200	79	$312	$4,799
83	Victorian	HPS	250-watt	102	Custom	$8.67	$2.03	$12.00	$15.17	$8.53	$6.50		76	905	64	1,045	102	$7,907	$22,046
64	Capitol Acorn	HPS	100-watt	43	Custom	$11.60	$2.41	$5.06	$14.34	$5.15	$2.74		30	61	1	92	43	$4,176	$1,764
67	Capitol Acorn	HPS	150-watt	62	Custom	$10.33	$2.24	$7.30	$14.28	$6.19	$3.95		-	358	9	367	62	$0	$9,623
65	Capitol Acorn	HPS	200-watt	79	Custom	$10.34	$2.25	$9.30	$15.38	$7.29	$5.04		1	61	-	62	79	$124	$1,647
66	Capitol Acorn	HPS	250-watt	102	Custom	$10.33	$2.24	$12.00	$16.83	$8.74	$6.50		-	-	-	0	102	$0	$0
12	Acorn - Indep.	HPS	100-watt	43	Custom	$8.14	$1.94	$5.06	$10.88	$4.68	$2.74		46	7	11	64	43	$4,493	$163
13	Acorn - Indep.	HPS	150-watt	62	Custom	$8.14	$1.94	$7.30	$12.09	$5.89	$3.95		-	4	4	8	62	$0	$93
98	Techtra	HPS	100-watt	43	Custom	$16.50	$3.06	$5.06	$19.24	$5.80	$2.74		533	38	2	573	43	$105,534	$1,395
99	Techtra	HPS	150-watt	62	Custom	$16.28	$3.03	$7.30	$20.23	$6.98	$3.95		17	144	-	161	62	$3,321	$5,236
88	Techtra	HPS	250-watt	102	Custom	$16.10	$3.00	$12.00	$22.60	$9.50	$6.50		-	60	74	134	102	$0	$2,160
90	Westbrooke Acorn	HPS	70-watt	30	Custom	$10.55	$2.27	$3.53	$12.46	$4.18	$0.00		1	24	-	25	30	$127	$654
91	Westbrooke Acorn	HPS	100-watt	43	Custom	$10.12	$2.21	$5.06	$12.86	$4.95	$2.74		31	273	6	310	43	$3,765	$7,240
92	Westbrooke Acorn	HPS	150-watt	62	Custom	$14.68	$2.81	$7.30	$18.63	$6.76	$3.95		-	61	-	61	62	$0	$2,057
93	Westbrooke Acorn	HPS	200-watt	79	Custom	$10.30	$2.24	$9.30	$15.34	$7.28	$5.04		-	5	-	5	79	$0	$134
94	Westbrooke Acorn	HPS	250-watt	102	Custom	$10.87	$2.31	$12.00	$17.37	$8.81	$6.50		73	35	-	108	102	$9,522	$970
62	Cobrahead	MH	150-watt	60	Custom	$4.94	$1.78	$7.06	$8.76	$5.60	$3.82		1	-	15	16	60	$59	$0
61	Flood	MH	350-watt	139	Custom	$5.43	$1.74	$16.36	$14.29	$10.60	$8.86		-	-	-	0	139	$0	$0
47	Flood	HPS	750-watt	285	Custom	$8.62	$2.82	$33.54	$26.79	$20.99	$18.17		55	-	-	55	285	$5,689	$0
9	Mongoose	HPS	150-watt	62	Custom	$8.39	$1.99	$7.30	$12.34	$5.94	$3.95		-	27	-	27	62	$0	$645
10	Mongoose	HPS	250-watt	102	Custom	$7.84	$1.92	$12.00	$14.34	$8.42	$0.00		-	4	-	4	102	$0	$92
18	Ornamental Acorn Twin / Opt C	QL	85-watt	64	Custom	$0.00	$0.00	$7.53	$0.00	$0.00	$4.08		-	-	102	102	64	$0	$0
20	Ornamental Acorn / Opt C	QL	55-watt	21	Custom	$0.00	$0.00	$2.47	$0.00	$0.00	$1.34		-	-	-	0	21	$0	$0
26	Ornamental Acorn Twin / Opt C	QL	55-watt	42	Custom	$0.00	$0.00	$4.94	$0.00	$0.00	$2.68		-	-	2	2	42	$0	$0
44	Composite Twin / Opt C	Comp	140-watt	54	Custom	$0.00	$0.00	$6.35	$0.00	$0.00	$3.44		-	-	6	6	54	$0	$0
45	Composite Twin / Opt C	Comp	175-watt	66	Custom	$0.00	$0.00	$7.77	$0.00	$0.00	$4.21		-	-	15	15	66	$0	$0
19	Cobrahead - (C) Only	MV	100-watt	39	Obsolete	$0.00	$0.00	$4.59	$0.00	$0.00	$2.49		-	-	-	0	39	$0	$0
21	Cobrahead	MV	175-watt	66	Obsolete	$4.37	$1.46	$7.77	$8.58	$5.67	$4.21		87	556	35	678	66	$4,562	$9,741
22	Cobrahead	MV	250-watt	94	Obsolete	$0.00	$0.00	$11.06	$0.00	$0.00	$5.99		-	-	12	12	94	$0	$0
23	Cobrahead	MV	400-watt	147	Obsolete	$5.25	$1.58	$17.30	$14.62	$10.95	$9.37		37	14	39	90	147	$2,331	$265
24	Cobrahead	MV	1,000-watt	374	Obsolete	$5.48	$1.85	$44.01	$29.32	$25.69	$23.84		8	-	1	9	374	$526	$0
50	Special Box - Space-Glo	HPS	70-watt	30	Obsolete	$5.37	$0.00	$3.53	$7.28	$0.00	$0.00		21	-	-	21	30	$1,353	$0
46	Special Box - Space-Glo	MV	175-watt	66	Obsolete	$5.33	$1.55	$7.77	$9.54	$5.76	$4.21		17	134	12	163	66	$1,087	$2,492
51	Box - Gardco Hub / Opt C	HPS	Twin 70-watt	60	Obsolete	$0.00	$0.00	$7.06	$0.00	$0.00	$3.82		-	-	18	18	60	$0	$0
52	Box - Gardco Hub / Opt C	HPS	70-watt	30	Obsolete	$0.00	$0.00	$3.53	$0.00	$0.00	$1.91		-	-	43	43	30	$0	$0
53	Box - Gardco Hub	HPS	100-watt	43	Obsolete	$0.00	$1.89	$5.06	$0.00	$4.63	$2.74		-	8	1	9	43	$0	$181
54	Box - Gardco Hub	HPS	150-watt	62	Obsolete	$0.00	$1.91	$7.30	$0.00	$5.86	$3.95		-	-	40	40	62	$0	$0
55	Box - Gardco Hub / Opt C	HPS	250-watt	102	Obsolete	$0.00	$0.00	$12.00	$0.00	$0.00	$6.50		-	-	32	32	102	$0	$0
56	Box - Gardco Hub / Opt C	HPS	400-watt	163	Obsolete	$0.00	$0.00	$19.18	$0.00	$0.00	$10.39		-	-	14	14	163	$0	$0
58	Box - Gardco Hub	MH	250-watt	99	Obsolete	$0.00	$1.24	$11.65	$0.00	$7.55	$6.31		-	7	3	10	99	$0	$104
59	Box - Gardco Hub	MH	400-watt	156	Obsolete	$0.00	$1.24	$18.36	$0.00	$11.18	$0.00		-	25	-	25	156	$0	$372
48	Cobrahead	MH	175-watt	71	Obsolete	$0.00	$1.65	$8.35	$0.00	$6.18	$4.53		-	2	16	18	71	$0	$40
60	Flood	MH	400-watt	156	Obsolete	$5.62	$1.80	$18.36	$15.56	$11.74	$9.94		20	3	6	29	156	$1,349	$65
69	Cobrahead DW 70/100	HPS	100-watt	43	Obsolete	$0.00	$1.52	$5.06	$0.00	$4.26	$0.00		-	-	-	0	43	$0	$0
70	Cobrahead DW 100/150	HPS	100-watt	43	Obsolete	$0.00	$1.52	$5.06	$0.00	$4.26	$0.00		-	-	-	0	43	$0	$0
71	Cobrahead DW 100/150	HPS	150-watt	62	Obsolete	$0.00	$1.53	$7.30	$0.00	$5.48	$3.95		-	3	-	3	62	$0	$55

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum				Monthly		Tariff Rates		Monthly	DAX Sch 91 & 95 A & B RATES				Proposed Sch 91 & 95 A & B Counts				Annual	Annual Fixed Revenue	
CODE	Light Description	Type	Watts	kWh	Category	A	B	Energy	A	B	C	TOTAL	A	B	C	TOTAL	MWh	A	B
2	Victorian	QL	85-watt	32	Obsolete	$0.00	$0.70	$3.77	$0.00	$2.74	$2.04		-	-	77	77	32	$0	$0
1	Victorian	QL	165-watt	60	Obsolete	$0.00	$0.83	$7.06	$0.00	$4.65	$3.82		-	-	166	166	60	$0	$0
3	Techtra	QL	165-watt	60	Obsolete	$17.55	$1.09	$7.06	$21.37	$4.91	$3.82		4	156	1	161	60	$842	$2,040
95	KIM SBC Shoebox	HPS	150-watt	62	Obsolete	$0.00	$2.38	$7.30	$0.00	$6.33	$3.95		-	29	33	62	62	$0	$828
96	KIM Archetype	HPS	250-watt	102	Obsolete	$0.00	$2.43	$12.00	$0.00	$8.93	$6.50		-	64	12	76	102	$0	$1,866
97	KIM Archetype	HPS	400-watt	163	Obsolete	$0.00	$2.12	$19.18	$0.00	$12.51	$10.39		-	16	15	31	163	$0	$407
80	Acorn Type	HPS	70-watt	30	Obsolete	$8.02	$1.96	$3.53	$9.93	$3.87	$0.00		22	10	-	32	30	$2,117	$235
73	GardCo Bronze - (C) Only	HPS	70-watt	30	Obsolete	$0.00	$0.00	$3.53	$0.00	$0.00	$1.91		-	-	14	14	30	$0	$0
72	GardCo Bronze - (C) Only	MV	175-watt	66	Obsolete	$0.00	$0.00	$7.77	$0.00	$0.00	$4.21		-	-	59	59	66	$0	$0
74	Acrylic Sphere - (C) Only	MV	400-watt	147	Obsolete	$0.00	$0.00	$17.30	$0.00	$0.00	$0.00		-	-	-	0	147	$0	$0
25	Post-Top - Black	HPS	70-watt	30	Obsolete	$4.73	$1.49	$3.53	$6.64	$3.40	$1.91		1,464	826	2	2,292	30	$83,097	$14,769
43	Rect.Type - (C) Only	HPS	200-watt	79	Obsolete	$0.00	$0.00	$9.30	$0.00	$0.00	$5.04		-	-	27	27	79	$0	$0
5	Incand. - (C) Only	IND	92-watt	31	Obsolete	$0.00	$0.00	$3.65	$0.00	$0.00	$1.98		-	-	10	10	31	$0	$0
6	Incand. - (C) Only	IND	182-watt	62	Obsolete	$0.00	$0.00	$7.30	$0.00	$0.00	$3.95		-	-	2	2	62	$0	$0
29	Town and Country Post-Top	MV	175-watt	66	Obsolete	$4.73	$1.49	$7.77	$8.94	$5.70	$4.21		80	834	8	922	66	$4,541	$14,912
27	Flood	HPS	70-watt	30	Obsolete	$4.32	$1.41	$3.53	$6.23	$3.32	$0.00		1	-	-	1	30	$52	$0
30	Flood	HPS	100-watt	43	Obsolete	$4.31	$1.51	$5.06	$7.05	$4.25	$2.74		45	4	-	49	43	$2,327	$72
38	Flood	HPS	200-watt	79	Obsolete	$5.45	$1.63	$9.30	$10.49	$6.67	$5.04		173	10	2	185	79	$11,314	$196
41	Cobrahead - PD	HPS	310-watt	124	Obsolete	$5.48	$1.91	$14.59	$13.38	$9.81	$7.90		5	-	1	6	124	$329	$0
14	Ornamental - (C) Only	HPS	100-watt	43	Obsolete	$0.00	$0.00	$5.06	$0.00	$0.00	$2.74		-	-	337	337	43	$0	$0
15	Twin Ornamental -(C) Only	HPS	Twin 100-watt	86	Obsolete	$0.00	$0.00	$10.12	$0.00	$0.00	$5.48		-	-	280	280	86	$0	$0
7	Flourescent - (C) Only	FLR	28-watt	12	Obsolete	$0.00	$0.00	$1.41	$0.00	$0.00	$0.76		-	-	6	6	12	$0	$0
100	Cobrahead	LED	37-watt	13	Standard	$2.89	$0.00	$1.53	$3.72	$0.00	$0.00		1,666	-	-	1,666	13	$57,777	$0
101	Cobrahead	LED	50-watt	17	Standard	$2.89	$0.00	$2.00	$3.97	$0.00	$0.00		24,839	-	-	24,839	17	$861,417	$0
102	Cobrahead	LED	52-watt	18	Standard	$3.22	$0.00	$2.12	$4.37	$0.00	$0.00		2,135	-	-	2,135	18	$82,496	$0
103	Cobrahead	LED	67-watt	23	Standard	$3.54	$0.00	$2.71	$5.01	$0.00	$0.00		5,258	-	-	5,258	23	$223,360	$0
104	Cobrahead	LED	106-watt	36	Standard	$4.31	$0.00	$4.24	$6.60	$0.00	$0.00		1,565	-	-	1,565	36	$80,942	$0
105	Cobrahead	LED	134-watt	46	Standard	$6.79	$0.00	$5.41	$9.72	$0.00	$0.00		17	-	-	17	46	$1,385	$0
106	Cobrahead	LED	156-watt	53	Standard	$7.91	$0.00	$6.24	$11.29	$0.00	$0.00		6	-	-	6	53	$570	$0
107	Cobrahead	LED	176-watt	60	Standard	$8.32	$0.00	$7.06	$12.14	$0.00	$0.00		-	-	-	0	60	$0	$0
108	Cobrahead	LED	201-watt	69	Standard	$7.62	$0.00	$8.12	$12.02	$0.00	$0.00		75	-	-	75	69	$6,858	$0
110	Acorn	LED	60-watt	21	Custom	$10.51	$0.00	$2.47	$11.85	$0.00	$0.00		44	-	-	44	21	$5,549	$0
111	Acorn	LED	70-watt	24	Custom	$12.15	$0.00	$2.82	$13.68	$0.00	$0.00		8	-	-	8	24	$1,166	$0
112	Westbrooke (non-fluted)	LED	53-watt	18	Custom	$14.34	$0.00	$2.12	$15.49	$0.00	$0.00		34	-	-	34	18	$5,851	$0
113	Westbrooke (non-fluted)	LED	69-watt	24	Custom	$13.96	$0.00	$2.82	$15.49	$0.00	$0.00		-	-	-	0	24	$0	$0
114	Westbrooke (non-fluted)	LED	85-watt	29	Custom	$14.97	$0.00	$3.41	$16.82	$0.00	$0.00		1	-	-	1	29	$180	$0
115	Westbrooke (non-fluted)	LED	136-watt	46	Custom	$16.99	$0.00	$5.41	$19.92	$0.00	$0.00		-	-	-	0	46	$0	$0
116	Westbrooke (non-fluted)	LED	206-watt	70	Custom	$16.71	$0.00	$8.24	$21.17	$0.00	$0.00		-	-	-	0	70	$0	$0
117	Westbrooke (fluted)	LED	53-watt	18	Custom	$16.28	$0.00	$2.12	$17.43	$0.00	$0.00		414	-	-	414	18	$80,879	$0
118	Westbrooke (fluted)	LED	69-watt	24	Custom	$16.28	$0.00	$2.82	$17.81	$0.00	$0.00		1	-	-	1	24	$195	$0
119	Westbrooke (fluted)	LED	85-watt	29	Custom	$15.31	$0.00	$3.41	$17.16	$0.00	$0.00		-	-	-	0	29	$0	$0
120	Westbrooke (fluted)	LED	136-watt	46	Custom	$18.00	$0.00	$5.41	$20.93	$0.00	$0.00		-	-	-	0	46	$0	$0
121	Westbrooke (fluted)	LED	206-watt	70	Custom	$18.00	$0.00	$8.24	$22.46	$0.00	$0.00		-	-	-	0	70	$0	$0
127	Westbrooke (non-flare)	LED	36-watt	12	Custom	$13.61	$0.00	$1.41	$14.37	$0.00	$0.00		-	-	-	0	12	$0	$0
128	Westbrooke (flare)	LED	36-watt	12	Custom	$14.63	$0.00	$1.41	$15.39	$0.00	$0.00		28	-	-	28	12	$4,916	$0
129	Post-Top, American Revolution	LED	45-watt	15	Custom	$6.44	$0.00	$1.77	$7.40	$0.00	$0.00		6	-	-	6	15	$464	$0
130	Post-Top, American Revolution	LED	72-watt	25	Custom	$5.93	$0.00	$2.94	$7.52	$0.00	$0.00		8	-	-	8	25	$569	$0
148	20 - 25	LED		8		$0.00	$0.00	$0.94	$0.00	$0.00	$0.51		-	-	54	54	8	$0	$0
149	>25 - 30	LED		9		$0.00	$0.00	$1.06	$0.00	$0.00	$0.57		-	-	36,514	36,514	9	$0	$0
150	>30 - 35	LED		11		$0.00	$0.00	$1.29	$0.00	$0.00	$0.70		-	-	1,344	1,344	11	$0	$0
151	>35 - 40	LED		13		$0.00	$0.00	$1.53	$0.00	$0.00	$0.83		-	-	5,117	5,117	13	$0	$0
152	>40 - 45	LED		15		$0.00	$0.00	$1.77	$0.00	$0.00	$0.96		-	-	2,662	2,662	15	$0	$0
153	>45 - 50	LED		16		$0.00	$0.00	$1.88	$0.00	$0.00	$1.02		-	-	3,012	3,012	16	$0	$0
154	>50 - 55	LED		18		$0.00	$0.00	$2.12	$0.00	$0.00	$1.15		-	-	1,965	1,965	18	$0	$0
155	>55 - 60	LED		20		$0.00	$0.00	$2.35	$0.00	$0.00	$1.27		-	-	6	6	20	$0	$0
156	>60 - 65	LED		21		$0.00	$0.00	$2.47	$0.00	$0.00	$1.34		-	-	8,142	8,142	21	$0	$0
157	>65 - 70	LED		23		$0.00	$0.00	$2.71	$0.00	$0.00	$1.47		-	-	965	965	23	$0	$0
158	>70 - 75	LED		25		$0.00	$0.00	$2.94	$0.00	$0.00	$1.59		-	-	141	141	25	$0	$0
159	>75 - 80	LED		26		$0.00	$0.00	$3.06	$0.00	$0.00	$1.66		-	-	7	7	26	$0	$0
160	>80 - 85	LED		28		$0.00	$0.00	$3.29	$0.00	$0.00	$1.78		-	-	65	65	28	$0	$0
161	>85 - 90	LED		30		$0.00	$0.00	$3.53	$0.00	$0.00	$1.91		-	-	3,756	3,756	30	$0	$0
162	>90 - 95	LED		32		$0.00	$0.00	$3.77	$0.00	$0.00	$2.04		-	-	-	0	32	$0	$0
163	>95 - 100	LED		33		$0.00	$0.00	$3.88	$0.00	$0.00	$2.10		-	-	27	27	33	$0	$0
164	>100 - 110	LED		36		$0.00	$0.00	$4.24	$0.00	$0.00	$2.29		-	-	1,843	1,843	36	$0	$0

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum CODE	Light Description	Type	Watts	Monthly kWh	Category	Tariff Rates A	Tariff Rates B	Monthly Energy	DAX Sch 91 & 95 A & B RATES A	B	C	TOTAL	Proposed Sch 91 & 95 A & B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	B
165	>110 - 120	LED		39		$0.00	$0.00	$4.59	$0.00	$0.00	$2.49		-	-	1	1	39	$0	$0
166	>120 - 130	LED		43		$0.00	$0.00	$5.06	$0.00	$0.00	$2.74		-	-	3	3	43	$0	$0
167	>130 - 140	LED		46		$0.00	$0.00	$5.41	$0.00	$0.00	$2.93		-	-	2,531	2,531	46	$0	$0
168	>140 - 150	LED		50		$0.00	$0.00	$5.88	$0.00	$0.00	$3.19		-	-	2	2	50	$0	$0
169	>150 - 160	LED		53		$0.00	$0.00	$6.24	$0.00	$0.00	$3.38		-	-	11	11	53	$0	$0
170	>160 - 170	LED		56		$0.00	$0.00	$6.59	$0.00	$0.00	$3.57		-	-	98	98	56	$0	$0
171	>170 - 180	LED		60		$0.00	$0.00	$7.06	$0.00	$0.00	$3.82		-	-	104	104	60	$0	$0
172	>180 - 190	LED		63		$0.00	$0.00	$7.41	$0.00	$0.00	$4.02		-	-	1,061	1,061	63	$0	$0
173	>190 - 200	LED		67		$0.00	$0.00	$7.88	$0.00	$0.00	$4.27		-	-	38	38	67	$0	$0
174	>200 - 210	LED		70		$0.00	$0.00	$8.24	$0.00	$0.00	$4.46		-	-	18	18	70	$0	$0
175	>210 - 220	LED		73		$0.00	$0.00	$8.59	$0.00	$0.00	$4.65		-	-	2	2	73	$0	$0
176	>220 - 230	LED		77		$0.00	$0.00	$9.06	$0.00	$0.00	$4.91		-	-	62	62	77	$0	$0
177	>230 - 240	LED		80		$0.00	$0.00	$9.41	$0.00	$0.00	$5.10		-	-	-	0	80	$0	$0
178	>240 - 250	LED		84		$0.00	$0.00	$9.88	$0.00	$0.00	$5.35		-	-	-	0	84	$0	$0
179	>250 - 260	LED		87		$0.00	$0.00	$10.24	$0.00	$0.00	$5.55		-	-	-	0	87	$0	$0
180	>260 - 270	LED		91		$0.00	$0.00	$10.71	$0.00	$0.00	$5.80		-	-	10	10	91	$0	$0
181	>270 - 280	LED		94		$0.00	$0.00	$11.06	$0.00	$0.00	$5.99		-	-	22	22	94	$0	$0
182	>280 - 290	LED		97		$0.00	$0.00	$11.41	$0.00	$0.00	$6.18		-	-	-	0	97	$0	$0
183	>290 - 300	LED		101		$0.00	$0.00	$11.88	$0.00	$0.00	$6.44		-	-	-	0	101	$0	$0
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								Totals					46,323	26,772	74,920	148,015	9,352	$2,134,966	$539,961

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

Annual Energy
$0
$3,461
$5,869
$13,169
$15,120
$4,833
$14,021
$259,699
$91,542
$345,179
$204,048
$233,612
$18,432
$71,119
$540,287
$3,219
$331,713
$34,164
$277,430
$131,137
$22,320
$150,480
$5,586
$32,149
$6,919
$0
$3,886
$701
$34,793
$14,104
$19,296
$1,059
$18,823
$5,344
$558
$15,552
$1,356
$0
$22,136
$2,365
$576
$9,217
$0
$119
$457
$1,399
$0
$63,217
$1,593
$18,684
$4,753
$890
$15,198
$1,525
$1,821
$546
$3,504
$4,608
$3,222
$1,398
$5,508
$1,804
$6,389
$0
$0
$263

Annual Energy
$3,483
$14,064
$13,640
$5,431
$10,944
$7,135
$1,356
$593
$5,501
$0
$97,089
$3,013
$438
$175
$85,967
$42
$2,975
$20,646
$1,050
$20,463
$34,003
$102
$30,588
$596,136
$54,314
$170,990
$79,627
$1,104
$449
$0
$7,308
$1,304
$271
$865
$0
$41
$0
$0
$10,532
$34
$0
$0
$0
$0
$474
$127
$282
$609
$464,458
$20,805
$93,948
$56,541
$67,951
$49,990
$169
$241,329
$31,382
$4,974
$257
$2,566
$159,104
$0
$1,257
$93,772

Annual Energy
$55
$182
$164,313
$141
$824
$7,750
$8,811
$94,344
$3,593
$1,780
$206
$6,741
$0
$0
$0
$1,285
$2,920
$0
$0

$5,966,787

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	$4.46	5,125	$274,290
59	Bronze	Fiberglass	30	A	$7.03	2,596	$218,999
61	Gray	Fiberglass	30	A	$7.57	5,154	$468,189
1	Standard	Wood	30 to 35	A	$5.08	1,466	$89,367
3	Standard	Wood	40 to 55	A	$6.63	184	$14,639
58	Black	Fiberglass	20	B	$0.14	5,097	$8,563
60	Bronze	Fiberglass	30	B	$0.23	5,000	$13,800
62	Gray	Fiberglass	30	B	$0.25	8,227	$24,681
46	Standard	Wood	30 to 35	B	$0.16	173	$332
47	Standard	Wood	40 to 55	B	$0.22	37	$98
31	Regular	Aluminum	16	A	$6.03	565	$40,883
32	Regular	Aluminum	25	A	$10.01	4,420	$530,930
33	Regular	Aluminum	30	A	$10.81	237	$30,744
28	Regular	Aluminum	35	A	$12.92	79	$12,248
18	Davit	Aluminum	25	A	$9.99	73	$8,751
6	Davit	Aluminum	30	A	$9.95	441	$52,655
29	Davit	Aluminum	35	A	$10.87	642	$83,742
70	Davit with 8-foot Arm	Aluminum	40	A	$14.73	39	$6,894
27	Double Davit	Aluminum	30	A	$14.64	24	$4,216
65	Fluted Victorian Ornamental	Aluminum	14	A	$8.81	66	$6,978
69	Non-fluted Techtra Ornamental	Aluminum	18	A	$17.32	539	$112,026
66	Fluted Ornamental	Aluminum	16	A	$9.00	222	$23,976
77	HADCO Non-fluted Ornamental	Aluminum	16	A	$0.00	0	$0
79	Fluted Westbrooke	Aluminum	18	A	$17.36	72	$14,999
81	Non-fluted Westbrooke	Aluminum	18	A	$18.40	459	$101,347
85	Decorative Ameron	Concrete	20	A	$0.00	0	$0
4	Ameron Post Top	Concrete	25	A	$0.00	0	$0
63	Fluted Ornamental -Black	Fiberglass	14	A	$10.66	668	$85,451
83	Smooth	Fiberglass	18	A	$4.46	2	$107
67	Regular - Color may vary	Fiberglass	22	A	$3.98	19	$907
68	Regular - Color may vary	Fiberglass	35	A	$6.51	350	$27,342
16	Anchor Base -Gray	Fiberglass	35	A	$11.83	51	$7,240
35	Direct Bury with Shroud	Fiberglass	18	A	$7.19	5	$431
34	Regular	Aluminum	16	B	$0.20	51	$122
8	Regular	Aluminum	25	B	$0.32	882	$3,387
48	Regular	Aluminum	30	B	$0.35	523	$2,197
54	Regular	Aluminum	35	B	$0.42	448	$2,258
13	Davit	Aluminum	25	B	$0.32	140	$538
12	Davit	Aluminum	30	B	$0.32	863	$3,314
53	Davit	Aluminum	35	B	$0.35	1,271	$5,338
76	Davit with 8-foot Arm	Aluminum	40	B	$0.48	161	$927
14	Double Davit	Aluminum	30	B	$0.47	46	$259
71	Fluted Victorian Ornamental	Aluminum	14	B	$0.29	1,119	$3,894
75	Non-fluted Techtra Ornamental	Aluminum	18	B	$0.56	404	$2,715
72	Fluted Ornamental	Aluminum	16	B	$0.29	1,557	$5,418
78	HADCO Non-fluted Ornamental	Aluminum	16	B	$0.00	0	$0

PORTLAND GENERAL ELECTRIC

Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
80	Fluted Westbrooke	Aluminum	18	B	$0.56	302	$2,029
82	Non-fluted Westbrooke	Aluminum	18	B	$0.60	131	$943
44	Painted Ornamental - Portland Rd.	Aluminum	35	B	$0.96	61	$703
86	Decorative Ameron	Concrete	20	B	$0.00	0	$0
5	Ameron Post Top	Concrete	25	B	$0.00	0	$0
64	Fluted Ornamental -Black	Fiberglass	14	B	$0.35	1,707	$7,169
84	Smooth	Fiberglass	18	B	$0.14	5	$8
73	Regular - Color may vary	Fiberglass	22	B	$0.13	504	$786
74	Regular - Color may vary	Fiberglass	35	B	$0.21	1,578	$3,977
17	Anchor Base -Gray	Fiberglass	35	B	$0.38	84	$383
36	Direct Bury with Shroud	Fiberglass	18	B	$0.23	527	$1,455
2	Post	Aluminum	30	A	$6.03	365	$26,411
30	Ornamental Post	Concrete	35 or less	A	$10.01	58	$6,967
37	Painted Regular	Steel	25	A	$10.01	294	$35,315
38	Painted Regular	Steel	30	A	$10.81	147	$19,069
39	Laminated without Mast Arm	Wood	20	A	$4.46	74	$3,960
24	Laminted SLO Pole	Wood	20	A	$4.46	5	$268
41	Curved laminated	Wood	30	A	$6.28	18	$1,356
11	Painted Underground	Wood	35	A	$5.08	185	$11,278
55	Bronze Alloy GardCo	Bronze	12	B	$0.18	0	$0
25	Ornamental Post	Concrete	35 or less	B	$0.32	186	$714
7	Painted Regular	Steel	25	B	$0.32	197	$756
49	Painted Regular	Steel	30	B	$0.35	24	$101
21	Unpainted with 6-foot Mast Arm	Steel	30	B	$0.32	5	$19
51	Unpainted with 6-foot Davit Arm	Steel	30	B	$0.32	0	$0
40	Unpainted with 8-foot Mast Arm	Steel	35	B	$0.35	32	$134
42	Unpainted with 8-foot Davit Arm	Steel	35	B	$0.35	1	$4
23	Laminated without Mast Arm	Wood	20	B	$0.14	1,456	$2,446
45	Curved laminated	Wood	30	B	$0.23	97	$268
26	Painted Underground	Wood	35	B	$0.16	265	$509
				Total Option As		24,644	$2,321,978
				Total Option Bs		33,161	$100,247
						57,805	$2,422,224

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

					Monthly Tariff Price			DAX Monthly Tariff Price				Annual	Revenues		
Code	**Description**	**Type**	**Size**	**kWh**	**Fixed**	**Energy**	**Total**	**Fixed**	**Energy**	**Total**	**Count**	**MWh**	**Fixed**	**Energy**	**Total**
Fixtures															
21	Cobrahead	MV	175-watt	66	$5.26	$7.77	$13.03	$5.26	$4.21	$9.47	364	288	$22,976	$33,939	$56,915
23	Cobrahead	MV	400-watt	147	$5.81	$17.30	$23.11	$5.81	$9.37	$15.18	1,882	3,320	$131,213	$390,703	$521,916
24	Cobrahead	MV	1000-watt	374	$6.04	$44.01	$50.05	$6.04	$23.84	$29.88	79	355	$5,726	$41,721	$47,447
33	Cobrahead - (non-pd)	HPS	70-watt	30	$5.30	$3.53	$8.83	$5.30	$1.91	$7.21	158	57	$10,049	$6,693	$16,742
34	Cobrahead - (non-pd)	HPS	100-watt	43	$5.30	$5.06	$10.36	$5.30	$2.74	$8.04	64	33	$4,070	$3,886	$7,956
35	Cobrahead - (non-pd)	HPS	150-watt	62	$5.41	$7.30	$12.71	$5.41	$3.95	$9.36	12	9	$779	$1,051	$1,830
39	Cobrahead - (non-pd)	HPS	200-watt	79	$5.80	$9.30	$15.10	$5.80	$5.04	$10.84	27	26	$1,879	$3,013	$4,892
36	Cobrahead - (non-pd)	HPS	250-watt	102	$5.68	$12.00	$17.68	$5.68	$6.50	$12.18	40	49	$2,726	$5,760	$8,486
41	Cobrahead - (PD)	HPS	310-watt	124	$6.04	$14.59	$20.63	$6.04	$7.90	$13.94	6	9	$435	$1,050	$1,485
37	Cobrahead - (non-pd)	HPS	400-watt	163	$5.75	$19.18	$24.93	$5.75	$10.39	$16.14	1,435	2,807	$99,015	$330,280	$429,295
30	Flood	HPS	100-watt	43	$5.20	$5.06	$10.26	$5.20	$2.74	$7.94	395	204	$24,648	$23,984	$48,632
38	Flood	HPS	200-watt	79	$6.01	$9.30	$15.31	$6.01	$5.04	$11.05	727	689	$52,431	$81,133	$133,564
31	Flood	HPS	250-watt	102	$5.96	$12.00	$17.96	$5.96	$6.50	$12.46	812	994	$58,074	$116,928	$175,002
32	Flood	HPS	400-watt	163	$5.96	$19.18	$25.14	$5.96	$10.39	$16.35	1,965	3,844	$140,537	$452,264	$592,801
76	Shoebox	HPS	70-watt	30	$6.62	$3.53	$10.15	$6.62	$1.91	$8.53	8	3	$636	$339	$974
77	Shoebox	HPS	100-watt	43	$6.31	$5.06	$11.37	$6.31	$2.74	$9.05	539	278	$40,813	$32,728	$73,541
78	Shoebox	HPS	150-watt	62	$6.63	$7.30	$13.93	$6.63	$3.95	$10.58	101	75	$8,036	$8,848	$16,883
81	Special Acorn	HPS	100-watt	43	$8.56	$5.06	$13.62	$8.56	$2.74	$11.30	347	179	$35,644	$21,070	$56,714
82	HADCO - Victorian	HPS	150-watt	62	$8.56	$7.30	$15.86	$8.56	$3.95	$12.51	21	16	$2,157	$1,840	$3,997
49	HADCO - Victorian	HPS	200-watt	79	$9.22	$9.30	$18.52	$9.22	$5.04	$14.26	2	2	$221	$223	$444
83	HADCO - Victorian	HPS	250-watt	102	$9.22	$12.00	$21.22	$9.22	$6.50	$15.72	0	0	$0	$0	$0
40	Early American Post-Top	HPS	100-watt	43	$5.68	$5.06	$10.74	$5.68	$2.74	$8.42	156	80	$10,633	$9,472	$20,105
62	Cobrahead	MH	150-watt	60	$5.83	$7.06	$12.89	$5.83	$3.82	$9.65	15	11	$1,049	$1,271	$2,320
48	Cobrahead	MH	175-watt	71	$5.90	$8.35	$14.25	$5.90	$4.53	$10.43	0	0	$0	$0	$0
61	Flood	MH	350-watt	139	$5.98	$16.36	$22.34	$5.98	$8.86	$14.84	252	420	$18,084	$49,473	$67,556
60	Flood	MH	400-watt	156	$6.17	$18.36	$24.53	$6.17	$9.94	$16.11	14	26	$1,037	$3,084	$4,121
47	Flood	HPS	750-watt	285	$9.18	$33.54	$42.72	$9.18	$18.17	$27.35	116	397	$12,779	$46,688	$59,466
12	HADCO Independence	HPS	100-watt	43	$8.70	$5.06	$13.76	$8.70	$2.74	$11.44	19	10	$1,984	$1,154	$3,137
13	HADCO Independence	HPS	150-watt	62	$8.70	$7.30	$16.00	$8.70	$3.95	$12.65	4	3	$418	$350	$768
64	HADCO Capitol Acorn	HPS	100-watt	43	$12.15	$5.06	$17.21	$12.15	$2.74	$14.89	9	5	$1,312	$546	$1,859
67	HADCO Capitol Acorn	HPS	150-watt	62	$10.88	$7.30	$18.18	$10.88	$3.95	$14.83	0	0	$0	$0	$0
65	HADCO Capitol Acorn	HPS	200-watt	79	$10.89	$9.30	$20.19	$10.89	$5.04	$15.93	0	0	$0	$0	$0
66	HADCO Capitol Acorn	HPS	250-watt	102	$10.88	$12.00	$22.88	$10.88	$6.50	$17.38	0	0	$0	$0	$0
98	HADCO Techtra	HPS	100-watt	43	$17.05	$5.06	$22.11	$17.05	$2.74	$19.79	0	0	$0	$0	$0
99	HADCO Techtra	HPS	150-watt	62	$16.83	$7.30	$24.13	$16.83	$3.95	$20.78	2	1	$404	$175	$579
88	HADCO Techtra	HPS	250-watt	102	$16.65	$12.00	$28.65	$16.65	$6.50	$23.15	0	0	$0	$0	$0
90	HADCO Westbrooke	HPS	70-watt	30	$11.10	$3.53	$14.63	$11.10	$1.91	$13.01	0	0	$0	$0	$0
91	HADCO Westbrooke	HPS	100-watt	43	$10.68	$5.06	$15.74	$10.68	$2.74	$13.42	0	0	$0	$0	$0
92	HADCO Westbrooke	HPS	150-watt	62	$15.23	$7.30	$22.53	$15.23	$3.95	$19.18	0	0	$0	$0	$0
93	HADCO Westbrooke	HPS	200-watt	79	$10.86	$9.30	$20.16	$10.86	$5.04	$15.90	0	0	$0	$0	$0
94	HADCO Westbrooke	HPS	250-watt	102	$11.43	$12.00	$23.43	$11.43	$6.50	$17.93	0	0	$0	$0	$0
9	Holophane Mongoose	HPS	150-watt	62	$8.94	$7.30	$16.24	$8.94	$3.95	$12.89	0	0	$0	$0	$0
100	Cobrahead	LED	37-watt	13	$3.28	$1.53	$4.81	$3.28	$0.83	$4.11	7	1	$276	$129	$404
101	Cobrahead	LED	50-watt	17	$3.28	$2.00	$5.28	$3.28	$1.08	$4.36	188	38	$7,400	$4,512	$11,912
102	Cobrahead	LED	52-watt	18	$3.61	$2.12	$5.73	$3.61	$1.15	$4.76	66	14	$2,859	$1,679	$4,538
103	Cobrahead	LED	67-watt	23	$3.81	$2.71	$6.52	$3.81	$1.47	$5.28	62	17	$2,835	$2,016	$4,851
104	Cobrahead	LED	106-watt	36	$4.57	$4.24	$8.81	$4.57	$2.29	$6.86	86	37	$4,716	$4,376	$9,092
105	Cobrahead	LED	134-watt	46	$6.39	$5.41	$11.80	$6.39	$2.93	$9.32	7	4	$537	$454	$991
106	Cobrahead	LED	156-watt	53	$7.51	$6.24	$13.75	$7.51	$3.38	$10.89	7	4	$631	$524	$1,155
107	Cobrahead	LED	176-watt	60	$7.92	$7.06	$14.98	$7.92	$3.82	$11.74	12	9	$1,140	$1,017	$2,157
108	Cobrahead	LED	201-watt	69	$7.22	$8.12	$15.34	$7.22	$4.40	$11.62	30	25	$2,599	$2,923	$5,522
110	Acorn	LED	60-watt	21	$11.06	$2.47	$13.53	$11.06	$1.34	$12.40	15	4	$1,991	$445	$2,435
111	Acorn	LED	70-watt	24	$12.70	$2.82	$15.52	$12.70	$1.53	$14.23	5	1	$762	$169	$931
112	Westbrooke (non-flare)	LED	53-watt	18	$14.89	$2.12	$17.01	$14.89	$1.15	$16.04	0	0	$0	$0	$0
113	Westbrooke (non-flare)	LED	69-watt	24	$14.51	$2.82	$17.33	$14.51	$1.53	$16.04	0	0	$0	$0	$0
114	Westbrooke (non-flare)	LED	85-watt	29	$15.52	$3.41	$18.93	$15.52	$1.85	$17.37	0	0	$0	$0	$0
115	Westbrooke (non-flare)	LED	136-watt	46	$17.54	$5.41	$22.95	$17.54	$2.93	$20.47	0	0	$0	$0	$0
116	Westbrooke (non-flare)	LED	206-watt	70	$17.26	$8.24	$25.50	$17.26	$4.46	$21.72	0	0	$0	$0	$0
117	Westbrooke (flare)	LED	53-watt	18	$16.84	$2.12	$18.96	$16.84	$1.15	$17.99	0	0	$0	$0	$0
118	Westbrooke (flare)	LED	69-watt	24	$16.84	$2.82	$19.66	$16.84	$1.53	$18.37	0	0	$0	$0	$0
119	Westbrooke (flare)	LED	85-watt	29	$15.87	$3.41	$19.28	$15.87	$1.85	$17.72	0	0	$0	$0	$0
120	Westbrooke (flare)	LED	136-watt	46	$18.56	$5.41	$23.97	$18.56	$2.93	$21.49	0	0	$0	$0	$0
121	Westbrooke (flare)	LED	206-watt	70	$18.56	$8.24	$26.80	$18.56	$4.46	$23.02	0	0	$0	$0	$0
122	CREE XSP	LED	25-watt	9	$2.44	$1.06	$3.50	$2.44	$0.57	$3.01	906	98	$26,528	$11,524	$38,052
123	CREE XSP	LED	42-watt	14	$2.52	$1.65	$4.17	$2.52	$0.89	$3.41	5,999	1,008	$181,410	$118,780	$300,190
124	CREE XSP	LED	48-watt	16	$2.92	$1.88	$4.80	$2.92	$1.02	$3.94	952	183	$33,358	$21,477	$54,835
125	CREE XSP	LED	56-watt	19	$3.35	$2.24	$5.59	$3.35	$1.21	$4.56	2,062	470	$82,892	$55,427	$138,319
126	CREE XSP	LED	91-watt	31	$3.35	$3.65	$7.00	$3.35	$1.98	$5.33	829	308	$33,326	$36,310	$69,636
127	Westbrooke (non-flare)	LED	36-watt	12	$13.20	$1.41	$14.61	$13.20	$0.76	$13.96	0	0	$0	$0	$0
128	Westbrooke (flare)	LED	36-watt	12	$14.23	$1.41	$15.64	$14.23	$0.76	$14.99	0	0	$0	$0	$0
129	Post-Top, American Revolution	LED	45-watt	15	$6.04	$1.77	$7.81	$6.04	$0.96	$7.00	15	3	$1,087	$319	$1,406
130	Post-Top, American Revolution	LED	72-watt	25	$5.52	$2.94	$8.46	$5.52	$1.59	$7.11	0	0	$0	$0	$0
Totals											20,819	16,413	$1,074,110	$1,931,749	$3,005,859
Poles															
1	Standard	Wood	30 to 35				$5.08				6,018				$366,857
3	Standard	Wood	40 to 55				$6.63				536				$42,644
11	Painted Underground	Wood	35				$5.08				20				$1,219
41	Curved laminated	Wood	30				$6.28				3				$226
31	Regular	Aluminum	16				$6.03				11				$796
32	Regular	Aluminum	25				$10.01				11				$1,321
33	Regular	Aluminum	30				$10.81				18				$2,335
28	Regular	Aluminum	35				$12.92				3				$465
65	Fluted Ornamental	Aluminum	14				$8.81				27				$2,854
18	Davit	Aluminum	25				$9.99				0				$0
6	Davit	Aluminum	30				$9.95				22				$2,627
29	Davit	Aluminum	35				$10.87				0				$0
70	Davit with 8-foot Arm	Aluminum	40				$14.73				0				$0
27	Double Davit	Aluminum	30				$14.64				3				$527
66	HADCO, Fluted Ornamental	Aluminum	16				$9.00				2				$216
69	HADCO, Non-fluted Techtra Ornamental	Aluminum	18				$17.32				19				$3,949
4	Ameron Post-Top	Concrete	25				$17.28				0				$0
63	Fluted Ornamental Black	Fiberglass	14				$10.66				176				$22,514
57	Regular Black	Fiberglass	20				$4.46				372				$19,909
61	Regular Gray	Fiberglass	30				$7.57				1,416				$128,629
68	Regular Other Colors	Fiberglass	35				$6.51				41				$3,203
16	Anchor Base Gray	Fiberglass	35				$11.83				2				$284
35	Direct Bury with Shroud	Fiberglass	18				$7.19				114				$9,836
79	Fluted Westbrooke	Aluminum	18				$17.36								
81	Non-Fluted Westbrooke	Aluminum	18				$18.40								
Totals											8,814				$610,413
Totals Luminaires and Poles															$3,616,272