BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

General Rate Case Filing
For Prices Effective January 1, 2016

PORTLAND GENERAL ELECTRIC COMPANY

ACRONYMS

February 12, 2015

UE 294 PGE ACRONYMS

401k – Portland General Electrtic 401(k) Plan
4-CP or 4-Coincident Peak – The monthly peak hours contained in the months of January, July, August, and December
A&G – Administrative and General
A/P – Accounts Payable
ACC – Arizona Corporation Commission
ACH – Automated Clearing House
ACI – Annual Cash Incentive
AFDC/AFUDC – Allowance for Funds Used during Construction
AGC – Automatic Generation Control
AMI – Advance Metering Infrastructure
AOP – Annual Operating Plan
ARM – Asset and Resource Manager
ASC – Accounting Standards Codification
AUT – Annual Update Tariff
B – Base
BA – Balancing Authority
BAA – Balancing Authority Area
BAL – Bank of America Leasing LLC
BCEM – Business Continuity and Emergency Management
Bcf – Billion Cubic Feet
BETC – Business Energy Tax Credits
BI – Business Intelligence Reporting Tool
BPA – Bonneville Power Administration
BVPS – Book Value per Share
CAISO – California Independent System Operator
CCCT – Combined Cycle Combustion Turbine
CE – Cost Element
CEI – Critical Energy Infrastructure
CEO – Chief Executive Officer
CET – Customer Engagement Transformation
CFA – Chartered Financial Analyst
CFO – Chief Financial Officer
CIAC – Contributions in Aid of Construction
CIP – Critical Infrastructure Protection
CIS – Customer Information System
CMC – Customer Marginal Costs
CME – Chicago Mercantile Exchange
CMS – Centers for Medicare and Medicaid Services
COS – Cost of Service
CPP – Critical Peak Pricing
CRPC – Columbia River Power Constructors
CRRA – Certified Rate of Return Analyst
CS&BD – Customer Strategies and Business Development
CSI – Centralization, Standardization and Integration

CSO – Customer Service Operations
CTG – Combustion Turbine Generator
CVR – Conversation Voltage Reduction
CWIP – Construction Work in Progress
D&O – Directors and Officers
DCF – Discounted Cash Flow
DDP – Dynamic Dispatch Program
DEQ – Department of Environmental Quality
DOE – Department of Energy
DNV-GL – Garrad Hassan America, Inc.
DP – Dynamic Programming
DPS – Dividends per Share
DR – Demand Response
DR – Data Request
DRA – Division of Ratepayer Advocates
DSG – Dispatchable Standby Generation
DSI – Dry Sorbent Injection
DTH – Decatherm
E – Post Price-Effect
EBITDA – Earnings Before Interest, Taxes, Depreciation and Amortization
EDD – Employment Development Department
EDI – Electronic Data Interchange
EE – Energy Efficiency
EFSC – Energy Facility Siting Council
EIA – Energy Information Administration
EIM – Energy Imbalance Market
ELS – Environmental Licensing Services
EOH – Equivalent Operating Hours
EPA – Environmental Protection Agency
EPRI – Electric Power Research Institute
EPS – Earnings per Share
ERISA – Employee Retirement Income Security Act
ERPs – Equity Risk Premiums
ES – Environmental Service
ES – Energy Storage
ESS – Energy Service Supplier
ETO – Energy Trust of Oregon
EV – Electric Vehicle
F&A – Finance and Accounting
FAS – Financial Accounting Standards
FASB – Financial Accounting Standards Board
Fed – Federal Reserve
FERC – Federal Energy Regulatory Commission
FICA – Federal Insurance Contributions Act
FITNES – Facility Inspections and Treatment to the National Electric Safety Code
FMBs – First Mortgage Bonds

FS – Feasibility Study
FSEC – Financial Systems Effectiveness Committee
FSRP – Financial Systems Replacement Project
FTE – Full Time Equivalent
GAAP – Generally Accepted Accounting Principles
GAC – G-Class Air Cooled
GAWE – Guaranteed Availability and Warranty Extension
GDP – Gross Domestic Product
GECC – General Electric Credit Corporation
GF – General Foreman
GIS – Geospatial Information System
GRC – General Rate Case
GTN – Gas Transmission Northwest, LLC
GWD – Graphic Work Design
HDHP – High Deductible Health Plan
HP/IP – High Pressure and Intermediate Pressure turbine
HPS – High pressure sodium
HR – Human Resources
HRA – Health Reimbursement Account
HRSG – Heat Recovery Steam Generator
I&C – Instrument and Control
IBEW – International Brotherhood of Electrical Workers
IC – Industrial Composite
ICE – IntercontinentalExchange
IE – Independent Evaluator
IPC – Idaho Power Company
IRP – Integrated Resource Plan
ISFSI – Independent Spent Fuel Storage Installation
ISO – Independent System Operator
IT – Information Technology
ITC – Investment Tax Credits
IVR – Interactive Voice Response
kW - Kilowatt
kWh – Kilowatt hours
kV – Kilovolt
kvar – Kilovolt ampere reactive
LEA – Line Extension Allowance
LED – Light-emitting diode
LGIA – Large Generator Interconnection Agreement
LRRA – Lost Revenue Recovery Adjustment
LSR – Lower Snake River
LTSA – Long-term Service Agreement
MAIFI – Momentary Average Interruption Frequency Index
MAP-21 – Moving Ahead for Progress in the 21st Century Act
MBA – Masters of Business Intelligence
MDCP – Managers Deferred Compensation Plan

MDMS – Meter Data Management System
MFRs – Minimum Filing Requirements
MH – Metal Halide
MHPSA – Mitsubishi Hitachi Power Systems America
Mid-C – Mid-Columbia
MMS – Maximo, Mobile and Scheduling
MONET – Multi-area Optimization Network Energy Transaction model
MPPS – Market Price per Share
MSI – Market Strategies International
MT – Magnetic Particle Testing
MV – Mercury Vapor
MWa – Megawatt average
MWh – Megawatt hours
NAICS – North America Industry Classification System
NCP – Non-coincident peak
NDE – Non-Destructive Examination
NDT – Nuclear Decommissioning Trust
NEPA – National Environmental Policy Act
NERC – North American Electric Reliability Corporation
NGTL – NOVA Gas Transmission, Ltd (TransCanada)
NIST – National Institute of Standards and Technology
NNMREC – Northwest National Marine Renewable Energy Center
NRC – Nuclear Regulatory Commission
NRSS – Non-running Station Service
NVPC – Net Variable Power Cost
NWN – Northwest Natural
NWPP MC – Northwest Power Pool Members Market Assessment and Coordination Committee
O&M – Operations and Maintenance
OATT – Open Access Transmission Tariff
OBI – Oracle Business Intelligence
ODEQ – Oregon Department of Environmental Quality
OE – Operational Efficiency
OEA – Office of Economic Analysis
OMS – Outage Management System
OMSI – Oregon Museum of Science and Industry
OOA – Ownership and Operation Agreement
OPIS – Oil Price Information Service
OPUC – Oregon Public Utility Commission
OSHA – Occupational Safety and Health Administration
OTC – Over-the-Counter
P – Price-Effect
PAC – PacificCorp
PAS – Publicly Available Specification
PBO – Pension Benefit Obligation
PCAM – Power Cost Adjustment Mechanism
PCB – Polychlorinated

PDL – Polynomial Distributed Lag
PG&E – Pacific Gas and Electric
PGE – Portland General Electric
PIC – Performance Incentive Compensation
PNCA – Pacific Northwest Coordination Agreement
PPA – Pension Protection Act
PPA – Prepaid Pension Asset
PPA – Power Purchase Agreement
PPC – Public Purpose Charges
PRB – Pelton and Round Butte plants
PRC – Power Resources Cooperative
PRPs – Potentially Responsible Parties
PSC – Portland Service Center
PSE – Puget Sound Energy
PSES – Power Supply Engineering Services
PSU – Portland State University
PT – Liquid penetrant method
PTCs – Production Tax Credits
PTP – Point-to-Point
PTSA – Precedent Transmission Service Agreement
PUD – Public Utility District
PwC – Price Waterhouse Coopers
PW1 – Port Westward 1
PW2 – Port Westward 2
R&D – Research and Development
R&ME – Reliability and Maintenance Excellence
RAP – Remedial Action Report
RC – Responsibility Center
RCA – Root Cause Analysis
RCM – Reliability Centered Maintenance
RE – Regional Entity
RES – Renewable Energy Standard
RFP – Request for Proposals
RI – Remedial Investigation
RLCOE – Real Levelized Cost of Energy
ROE – Return on Equity
ROM – Resource Optimization Model
RROE – Required Return on Equity
RP – Risk Premium
RP – Renewable Power
RPS – Renewable Portfolio Standard
RRMP – Recreation Resources Management Plan
RSP – Retirement Savings Plan
RTDT – Real Time Dispatch Tool
RTO – Regional Transmission Organization
S&P – Standard & Poor's

SAIDI – System Average Interruption Duration Index
SAIFI – System Average Interruption Frequency Index
SB – Senate Bill
SCADA – Supervisory Control and Data Acquisition
SCCT – Simple Cycle Combustion Turbine
SCD – Scheduling Control and Dispatch
SCED – Security Constrained Economic Dispatch
SEC – Securities Exchange Commission
SEDC – Safe and Efficient Design Construction
SEI – Siemens Energy
SEM – Scanning Electron Microscope
SERP – Supplemental Executive Retirement Plan
SFAS – Statement of Financial Accounting Standards
SG – Smart Grid
SHARP – Safety and Health Achievement Recognition Program
SIP – Strategic Investment Program
SITF – Supervisor in the Field
SMA – Service and Maintenance Agreement
SME – Soy Methyl Ester
SNA – Sales Normalization Adjustment
SQM – Service Quality Measure
SR – System Reliability
SSPC – Salem Smart Power Center
STD – Short-term Disability
SY – System Resiliency
T&D – Transmission and Distribution
TCC – Tualatin Contact Center
TID – Turlock Irrigation District
TIV – Total Insured Value
TOU – Time-of-Use
TQS – TQS Research, Inc.
TSRs – Transmission Service Requests
UAM – Utility Asset Management
UG – Underground
USWC – US West Communications
UT – Ultrasonic testing
VER – Variable Energy Resource
VERBS – Variable Energy Resource Balancing Service
VIE – Variable Interest Entities
VoIP – Voice over Internet Protocol
VPP – Voluntary Protection Program
W&S – Wages and Salaries
WECC – Western Energy Coordinating Council
WIES – Western Interconnected Electric Systems
WMS – Work Management System
WNA – Wärtsilä North America

WSATA – Western States Association of Tax Administrators
WSPWE – Warm Spring Power and Water Enterprises
WTG – Wind Turbine Generators

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PORTLAND GENERAL ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBITS

February 12, 2015

BEFORE THE PUBLIC UTILITY COMMISSION

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UE 294

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

James J. Piro
Jim Lobdell

February 12, 2015

Table of Contents

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:

- Describe the context of this filing and the drivers resulting in the proposed price increase of approximately 3.7%;
- Describe the addition of the Carty Generating Station (Carty), a 441 MW gas-fired combined cycle plant located in Boardman, Oregon, expected to come on line in the second quarter of 2016 and its contribution to this proposed price increase;
- Describe how this plant meets our need for an additional base load energy resource, as identified in our Integrated Resource Plan (IRP);
- Discuss PGE's progress toward participating in an Energy Imbalance Market (EIM);
- Discuss PGE's continuous improvement efforts;
- Discuss our efforts to mitigate the impact of the price increase, in keeping with our long-term strategy of minimizing price volatility for customers; and
- Identify our other key proposals.

Our testimony is organized according to these objectives.

II. Context

Q. What is the business context for this rate case filing?

A. The business context is our responsibility to provide safe, reliable electricity with excellent customer service at a reasonable price for our customers. This context is influenced by the economy, customer choices and preferences, and compliance with regulations – including our obligation to plan and implement actions to meet our customers' current and future energy needs with both demand and supply-side resources that provide the best balance of cost and risk over time.

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

A. The economy impacts our business because economic growth results in load growth. Load growth, and the net margin it produces, enables us to absorb normal inflationary cost increases. While industrial load growth is a cautious bright spot in the forecast, we expect modest or no load growth for commercial and residential customers when compared with 2014 actual weather-adjusted deliveries due primarily to energy efficiency, which reduces use per customer, and lower than historical new customer connects. Recognizing this, we continue to focus on a culture of continuous improvement and implementing strategies that increase the efficiency and effectiveness of our operations in all areas of the company while maintaining excellent service to customers.

Q. What has PGE done to reduce costs since filing its last general rate case?

A. We continue to conduct benchmarking reviews of our core functions, identifying best practices and adopting improvements where it makes economic sense and aligns with our business objectives. PGE Exhibit 101 contains current and upcoming benchmarking efforts.

Q. How is PGE's business context influenced by customer choices and preferences?

A. We are in business to serve our customers' energy needs. Our customers have alternatives: nonresidential customers may choose an alternate energy supplier and residential customers have fuel choices and access to distributed technologies.

In addition, energy efficiency as the resource of choice – among public policy makers, regulators, customer advocates, and within PGE itself – reduces load growth that would otherwise be expected to accompany population and economic expansion. This prioritization of energy efficiency mirrors our customers' preferences as well, and is reflected by a 12% reduction in average monthly residential energy use since 2000. We support, and will continue to support, energy efficiency because it benefits our customers and our service area in many ways. To give more perspective on our support for energy efficiency, in 2014, we collected about $88 million for the Energy Trust of Oregon (ETO) and other agencies to fund programs for our customers to be more energy efficient. The ETO's projection for cost-effective energy efficiency acquired is 30.9 MWa for 2015 and 34.9 MWa for 2016. The projected 34.9 MWa of energy efficiency is approximately 1.3% of PGE's cost of service test year load forecast.

Q. Are there other consequences to PGE's commitment to pursue cost-effective energy efficiency?

A. Yes. In the long-run, our commitment to energy efficiency helps PGE displace the need for long-term, supply-side resources. We are steadfast in our commitment to cost-effective energy efficiency as a 'first choice' resource. However, in the short-term, energy efficiency leads to a reduction in contributions that would otherwise help offset our existing fixed costs, which raises customer prices on average, but also lowers customer bills because of reduced usage. Despite these consequences, we remain committed to the pursuit of energy efficiency. In our most recent general rate case (UE 283), PGE agreed to support an investigatory docket to consider the question of whether customers with loads greater than 1 MWa are receiving a direct benefit from energy efficiency measures funded by amounts pursuant to Senate Bill 838.

Q. What future challenges is PGE facing related to customer choice?

A. PGE has seen increased adoption of distributed solar in recent years. While customers should continue to have the option to install solar generation on their premises, the current regulatory framework does not adequately address the subsidization of these customers by the rest of PGE's customers.

The Public Utility Commission of Oregon (OPUC) recently opened a value of solar docket (UM 1716) and PGE looks forward to participating in it. Though PGE does not have a specific proposal in this general rate case, we think some of the policy issues can be addressed through pricing mechanisms such as a customer charge that differentiates between the distributed generation customers' use and benefits from the grid, and the use and benefits for other customers. We also hope to evaluate options considered by other states, including those most recently adopted in Wisconsin.

Q. What else do customers expect of PGE?

A. In addition to supporting energy efficiency, customers expect us to deliver electricity safely and reliably, while also fulfilling broader mandates for a changing resource mix with a reduced environmental footprint that meets all applicable standards and regulations. Customers also expect excellent customer service that meets or exceeds their experience with other service providers. Finally, they expect us to operate efficiently and cost-effectively, and make prudent resource decisions to meet their electricity needs efficiently and reliably. Our investment in Carty is an illustration of this effort.

Q. How is PGE's business context influenced by changes in energy markets?

A. Today, PGE and the majority of the other 37 Balancing Authorities (BAs) in the Western Interconnect operate in an hourly dispatched bilateral energy market to purchase, sell and balance their respective resource portfolios. With the increased concentration of variable energy renewable resources (VERs) such as wind and solar on the electric grid, it has become imperative for maintenance of grid reliability that the timing of generation redispatch advance closer to the moment of delivery, generally referred to as "automated within-hour" dispatch. Achieving this goal will allow for greater optimization of the overall power grid and service reliability. In an attempt to accomplish this goal, often referred to as creation of an EIM, we are evaluating two potential market models: 1) the Northwest Power Pool (NWPP) Market Assessment and Coordination Committee (MC) Initiative, which seeks to enhance operational tools for NWPP MC Members and design an automated within-hour energy market to meet their unique needs; and 2) the California Independent System Operator (CAISO) EIM, which has offered to extend its automated within-hour market to PGE and others in the Western Interconnection.

Q. What steps has PGE taken toward an automated within-hour market?

A. PGE is working on several fronts to prepare to participate in an automated within-hour market. Some of these fronts include: (1) the evaluation and design of company systems, operations and generation capability to enable PGE to allow for sub-hourly scheduling and dispatch of resources; and (2) taking a lead role in the NWPP MC Initiative market design. In addition, we are preparing to operate under sub-hourly dispatch beginning

October 1, 2015, at which time we will schedule under BPA's 30/15 variable energy resource balancing service (VERBS) committed scheduling rate (this is more fully discussed in PGE Exhibit 400). PGE is also conducting a study, consistent with the Commission's directive in PGE's most recent IRP docket (LC 56), to evaluate the quantitative and qualitative benefits of participating in the CAISO EIM or NWPP MC Initiative. The results of this study will inform PGE on which market would provide the best value for our customers. PGE is currently targeting some form of EIM participation during the latter part of 2017.

Q. What are your goals for PGE?

A. First and foremost: deliver safe, reliable and 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) be viewed by our customers as a trusted energy partner; 2) be a preferred employer, attracting and retaining exceptional people; 3) maintain a reputation as a caring and invested community partner; and 4) attract investors by offering a competitive return on capital invested.

Q. Does this rate case further the goals you just articulated?

A. Yes. The current case is necessary due primarily to the addition of Carty, which is expected to be placed in service in the second quarter of 2016. We are filing this rate case to bring it into customer prices when it begins serving customers. Carty was chosen in a competitive RFP process to meet the energy demands of PGE's customers. This plant is the result of Action Plan implementation from PGE's 2009 IRP (updated in 2011 and 2012). While the specific project was selected following a competitive RFP process in 2012, the need to bring this base load resource into our portfolio has been anticipated for some time (we identified the need for a base load unit and the Commission acknowledged it in our 2009 IRP). Carty will be a highly efficient, natural-gas fired generating plant using a Mitsubishi G-class turbine. The plant is discussed in greater detail in PGE Exhibit 300. We are diligently working with the engineering, procurement and construction contractor to bring this facility into service on time, on scope, and on budget.

Q. Aside from Carty, in what other areas are costs increasing?

A. PGE is facing cost increases in various areas discussed in more detail elsewhere in PGE's direct testimony, including costs related to:

- Essential modernization and upgrades to our Information Technology platforms with the implementation of new systems including Maximo, Mobile and Scheduling Wave 2 (MMS), Geographic Information System/Graphic Work Design (GIS/GWD) and Outage Management System (OMS);
- Enhanced Business Continuity and Emergency Management capability to achieve a target level of resilience among PGE's primary departments/systems;
- Customer Service efforts to modernize and integrate systems through Customer Engagement Transformation, and to offer customers the ability to transact with PGE as they do other providers through the fee-free bankcard program; and
- Environmental Services compliance with hydro licensing requirements and mandatory environmental cleanup efforts.

We have taken steps to offset the request in this case through Continuous Improvement (Section III) and specific mitigation efforts (Section IV).

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

A. This case also 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 will benefit customers through improved service and long term cost impacts.

III. Continuous Improvement Cycle

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

A. As discussed in detail in the last two general rate cases (UE 262 and UE 283), 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 move PGE's culture toward 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 transmission and distribution reliability, high 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 quarterly. In addition, within each of these areas accountability is assigned and cascaded down to the scorecards of managers throughout the organization to ensure alignment. This scorecard process allows management and employees to understand their respective deliverables, with continuous improvement being an integral part of that process.

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 searching for 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. While most of these efforts are led by PGE's Corporate Performance Management team, the ultimate responsibility to continually improve remains with all PGE employees. These efforts include benchmarking, which PGE uses to help each functional area understand how we compare to functional areas in similar 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, process 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 go on?

A. PGE's continuous improvement process is an ongoing effort with incremental savings 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 the 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 big-dollar cost savings on a consistent, annual basis. This case reflects the savings achieved to date, with incremental savings achieved since 2014 discussed in the pertinent portions of testimony.

Q. Please describe the Process Improvement Program.

A. PGE is piloting its Process Improvement Program to:

- Provide common tools that minimize inconsistency across improvement and efficiency work;
- Build internal capability and capacity, making PGE less dependent on external consultants;
- Train leaders to help facilitate the process improvement culture and environment;
- Provide a central governance process to improve awareness and tracking of results in alignment with strategic priorities; and
- Reinforce a culture of improvement and best practices in employees' daily work and continuously monitor and measure results.

Participants from the Finance, Supply Chain, and Transmission & Distribution organizations have evaluated and implemented improvements on a number of processes including pole tag creation/installation, financial statement development, and project portfolio management. As PGE conducts benchmarking and best practices studies and implements programs such as the Process Improvement Program, we are ensuring that PGE's employees are supported as we build a culture of continuous improvement.

Q. What is PGE doing to manage the change occurring throughout the organization?

A. Change Management is a structured approach to shifting and transitioning individuals, teams, and organizations from their current state to a desired future state. Change Management is critical because it increases the success rate of organizational changes by supporting employees and the organization throughout the change while minimizing organizational disruption that could – at least temporarily – reduce our effectiveness in serving customers. We have employed a Change Management Group to assist employees with the change process and to serve as the central resource to provide change management consulting services to facilitate change capability and readiness. PGE's Change Management Group is creating change competency and empowering individuals, teams and organizations to embrace positive change in the current business environment.

IV. Mitigation and Price Increase

Q. What have you done 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 reduced our request related to incentive compensation costs even though the entirety of the incentive program benefits customers and is a key part PGE's total compensation, 2) we removed 50% of certain layers of directors and officers insurance, and 3) we requested a return on equity at the low end of the range supported by PGE's expert witness.

Q. What else is PGE proposing to mitigate the price increase in this case?

A. As further mitigation we propose to accelerate the refund of excess funds in the Trojan Nuclear Decommissioning Trust previously approved in OPUC Order No. 14-422. Specifically, PGE would refund the amount currently slated for 2017 in 2016 instead, reducing PGE's request in this case by nearly 1%. The refund is discussed in PGE Exhibit 1400.

Q. What is the overall price increase that PGE is requesting in this proceeding?

A. With Commission approval of all elements of this filing, PGE cost of service and direct access customers would see an overall 3.7% increase in customer prices. This includes Carty, the accelerated refund planned with regard to the Trojan Nuclear Decommissioning Trust, and additional Regional Power Act Exchange benefits (applied to eligible customers) of approximately $15 million. Beginning in January 2016, customers will experience an overall price decrease of 1.0% followed by an increase of 4.7% when Carty enters service in the second quarter of 2016, yielding the overall net increase of 3.7% in 2016 (see PGE Exhibit 1400 for more detail).

V. Other Key Proposals

Q. Besides the addition of Carty, what other key proposals are in this rate case?

A. Our case includes the following key proposals:

- A major maintenance accrual for Carty similar to the accruals used for the Port Westward 1, Port Westward 2 and Coyote Springs plants, which is further discussed in PGE Exhibit 300.
- A forecasted actual 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 return on equity of 9.9%, which is at the low end 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 10.25%, which is above the sample average because PGE has more risk than the average utility in the sample. Our recommended 9.9% rate reflects our desire to help mitigate the impact of increased costs on our customers. The 9.9% rate, while below the recommended average estimated by Dr. Villadsen, would still provide a fair investment opportunity for shareholders.

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 generate sufficient cash flow with which to fund capital investments, meet its financial obligations, and provide a fair opportunity for our shareholders to earn a reasonable return on their investment.

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 2016 test year revenue requirement, comparing the request with the 2014 actuals. This testimony also discusses PGE's rate base, the costs associated with Carty, and how PGE proposes to include them in rates.
- In Exhibit 300 Maria Pope, Senior Vice President of Power Supply and Operations and Resource Strategy, and Jim Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, describe the new generation resource, Carty. In addition, the witnesses review the extensive planning and competitive bidding processes that led to the selection of the project. Finally, this joint testimony discusses the cost of the resource and PGE's progress to date to bring the project into service, on time and on budget.
- In Exhibit 400, Managers Mike Niman, Terri Peschka, and Patrick Hager 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 2015 NVPC forecast.
- In Exhibit 500, Arleen Barnett, Vice President of Administration and Jardon Jaramillo, Director of Compensation and Benefits, present PGE's compensation costs for the 2016 test year, efficiency gains, changes to compensation policies and plans, and proposed pension cost recovery.
- In Exhibit 600, Jim Lobdell, Senior Vice President, Finance, Chief Financial Officer and Treasurer, Cam Henderson, Vice President of Information Technology (IT) and Chief

Information Officer, and Alex Tooman, Project Manager, explain PGE's costs and cost drivers related to corporate support operations including insurance, environmental services, business continuity and emergency management and information technology.

- In Exhibit 700, Stephen Quennoz, Vice President of Power Supply 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 ongoing efforts to improve plant performance, reliability and safety.
- 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 2016 test year transmission and distribution O&M expenses and the status of our work on implementing new systems including MMS, GIS/GWD and OMS.
- 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 2016 test year; provide an update on the Customer Engagement Transformation project and fee-free bankcard program; and discuss improvement initiatives.
- In Exhibit 1000, Patrick Hager, Manager of Regulatory Affairs, and Brett Greene, Assistant Treasurer and Director of Treasury and Tax recommend PGE's cost of capital and capital structure for the 2016 test year.
- In Exhibit 1100, Bente Villadsen, economist and principal at The Brattle Group estimates PGE's required return on equity and describes the supporting analysis undertaken.
- In Exhibit 1200, Sarah Dammen and Amber Riter, economists, provide the initial load forecast, and explain the process and method in forecasting the 2016 test year load.

- In Exhibit 1300, Rob Macfarlane, Senior Analyst, and Bruce Werner, Analyst, describe marginal cost studies for distribution, customer service and generation.
- In Exhibit 1400, Marc Cody, Senior Pricing Analyst, describes how the proposed tariff changes recover PGE's 2016 revenue requirement to achieve fair, just and reasonable prices for our customers.

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 Portland General Electric Company 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., Oregon State University Foundation, 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 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 Portland General Electric Company in 1984 I have held a variety of positions at

PGE and its affiliates. I entered my current position as Senior Vice President, Finance, Chief Financial Officer, and Treasurer in March 2013.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	Projected Benchmarking Schedule

Projected Benchmarking Schedule

Portland General Electric

Next Benchmark	Function	Previous Benchmark	Data Year Analyzed	Cycle (Yrs)
2015	Human Resources	2010	2009	5
	Fleet	2014	2013	Annually
2016	Generation	2010	2007 - 2009	6
	Transmission & Distribution	2011	2010	5
	Information Technology	2012	2011	4
	Public Policy	2012	2011	4
	Legal	2012	2010 - 2011	4
	Fleet	2015	2014	Annually
2017	Fleet	2016	2015	Annually
2018	Customer Service	2012	2011	6
	Finance	2014	2013	4
	Procurement	2014	2014	3
	PSES	2014	2014	4

UE 294 / PGE / 200
Tooman - Brown

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Alex Tooman
Rebecca Brown

February 12, 2015

Table of Contents

I. Introduction

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

A. My name is Alex Tooman. I am a 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. In addition, my areas of responsibility include rate base, incentives, benefits, and insurance.

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 2016 revenue requirement for the following components:

1. Base business
2. Carty Generating Station (Carty)

Carty is separate from base business because we expect it to be in service during the second quarter of 2016.

Q. What increase does PGE expect on January 1, 2016?

A. PGE requests a base business increase of $38.8 million or 2.2% effective January 1, 2016 before the consideration of Carty. This increase is relative to the revenues we expect based on 2015 prices, which reflect approved prices in UE 283 and UE 286. This revenue requirement will allow PGE an opportunity to earn a 7.7% rate of return that includes a 9.9% return on average common equity (ROE) of 50% in 2016. PGE Exhibit 201, columns 1 through 3, summarizes the development of PGE's 2016 revenue requirement for base business.

Q. Is Carty included in your request for $38.8 million of additional revenue?

A. No. As shown in PGE Exhibit 201, column 5, we calculate the incremental annualized revenue requirement increase related to Carty of approximately $83.6 million. PGE requests the Public Utility Commission of Oregon (OPUC) authorize tariffs to collect the annualized amount beginning with the in-service date of Carty. We currently expect Carty to be in service in the second quarter of 2016. To the extent the in-service date changes, the effective date of the tariffs to recover the incremental impact of Carty will change accordingly. In Section VII we discuss the incremental revenue requirement of Carty.

Q. Were mitigating actions taken to help limit the size of the requested increase in this filing?

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

1. Reducing our request related to incentive compensation costs;
2. Achieving savings from continuous improvements and efficiency efforts to improve operation in various parts of PGE;
3. Removing 50% of certain layers of Directors & Officers (D&O) insurance;
4. Accelerating the refund of excess funds in the Trojan Decommissioning Trust;
5. Requesting a return on equity at the low end of the range supported by PGE's expert witness; and
6. Reducing our wage and salary escalation.

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 2016?

A. As shown in column 1 of PGE Exhibit 201, without a price increase we would expect PGE's ROE to be approximately 8.8% in 2016 before Carty is in service, lower than the authorized ROE of 9.68%. With the Carty revenue requirement included, PGE's ROE would be 6.7% without a price increase.

B. Structure of the Case

Q. Please summarize PGE's 2016 revenue requirement prior to Carty.

A. Table 1 below summarizes PGE's 2016 revenue requirement by major category and provides a comparison to the results of UE 283. We also list the PGE testimony that addresses each specific cost category.

Table 1

Revenue Requirement Summary
($ in millions)

Rev Req Category	UE 283 Approved	2016 Budget	Exhibit	No.
Sales to Consumers	$1,779.8	$1,837.8	Rev Req	200
Other Revenue	$ 25.8	$ 25.1	Rev Req	200
NVPC	$ 562.3	$ 556.9	Power Costs	400
Production O&M	$ 150.1	$ 146.0	Production	700
Transmission O&M	$ 15.0	$ 14.3	T&D	800
Distribution O&M	$ 94.6	$ 94.5	T&D	800
Customer Service	$ 69.1	$ 72.1	Customer Svc.	900
A&G	$ 140.9	$ 153.0	Corp. Support	600
Depr. & Amort.	$ 300.2	$ 320.0	Rev Req	200
Other Taxes	$ 120.0	$ 122.7	Rev Req	200
Income Taxes	$ 52.2	$ 63.0	Rev Req	200
Operating Income	**$ 286.2**	**$ 305.3**		
Return on Equity	9.68%	9.90%	Return on Equity	1100

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 2016 revenue requirement?

A. We developed the revenue requirement based on PGE's 2015 budgets, which were based on UE 283 prices as authorized by Commission Order No. 14-422. The 2015 budgets were escalated for inflation to 2016 and updated for known and measureable changes which primarily consist of PGE's new generating resource - Carty.

Q. What rates did you use to escalate the 2015 budget to 2016 test year?

A. We applied the following escalation rates to the 2015 budget:

- 3% average rate for all labor (at applicable effective dates[1]).
- 3% for outside services (cost elements (CE) 1502, 1602, 2200, and 2300), effective May 1.
- 2% for direct materials (CE 210 and 2110), effective January 1.
- 1.6% 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, U.S. Economic Outlook dated September 2014. Wage escalation is based on the forecast of compensation costs described in PGE Exhibit 500.

Q. What comparison with the 2016 test year costs do you make in the testimonies generally?

A. We compare our forecast of 2016 test year costs to 2014 actuals because 2014 represents PGE's most recent year with actual results. The increases/decreases in this filing will be analyzed on an average annual basis for the differences between 2014 actuals and the 2016 test year.

Q. Did you adjust PGE's 2016 revenue requirement to reflect previous pricing decisions and other regulatory policies?

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

[1] March 1 for bargaining employees and April 15 for non-bargaining employees.

Table 2
Regulatory Adjustments
($ in millions)

Category	O&M	Rate Base
Retail Services	$(0.1)	$(0.1)
Charitable Contributions	$(1.1)	
State & Federal Lobbying	$(1.0)	
Memberships and Dues	$(0.2)	
MDCP	$(5.0)	
SERP	$(1.4)	
Image Advertising	$(0.7)	
Total Adjustments	**$(9.5)**	**$(0.1)**

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 $1.1 million from cost of service;
- State and federal lobbying: excluded the entire $1.0 million from cost of service;
- Memberships and dues: removed approximately $0.2 million, which reflects the pricing treatment received in PGE's previous rate case dockets;
- Managers' Deferred Compensation Plan (MDCP): removed the entire $5.0 million;
- Supplemental Executive Retirement Plan (SERP): removed the entire $1.4 million; and
- Corporate image advertising: removed the entire $0.7 million from cost of service.

II. Other Revenue

Q. What is PGE's 2016 forecast of Other Revenue?

A. PGE forecasts 2016 Other Revenue of $25.1 million. This compares to 2014 Other Revenue of $27.5 million. The decrease is attributable to PGE receiving a settlement in 2014 from the Bonneville Power Administration (BPA) for wind curtailment in 2011. This caused 2014 to be above average, hence the decrease in 2016.

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 2016 test year?

A. Yes. We adjusted the 2016 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 2016.

III. Depreciation

Q. What is PGE's estimate for 2016 depreciation expense?

A. We estimate $270.4 million in depreciation expense for the 2016 test year excluding Carty. PGE Exhibit 203 summarizes the test year depreciation expense by plant type and provides a comparison to 2014 actuals, plus filed and settled depreciation forecasts from PGE's prior general rate case, UE 283.

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

A. No. PGE's most recent depreciation study was approved in Docket No. UM 1679 and PGE switched to the new depreciation rates starting January 1, 2015.

Q. How does PGE's 2016 depreciation expense compare to 2014 actuals?

A. Actuals for 2014 were $245.9 million, which results in a $24.5 million increase for 2016.

Q. What is the main driver for the increase?

A. The main driver of the increase in depreciation expense is the addition of Port Westward 2 (PW2) and Tucannon River Wind Farm (Tucannon) to PGE's plant-in-service in late 2014; this accounts for a $24.9 million increase as approved by Commission Order No. 14-422. Changes in other categories net to approximately zero as can be seen in PGE Exhibit 203.

Q. How did PGE account for Carty's 2016 depreciation expense?

A. Carty's depreciation expense of $14.4 million is not included in the base case and is discussed in more detail in PGE Exhibit 300.

IV. Amortization

Q. What is amortization?

A. Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life, but 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.

Q. Please summarize PGE's 2016 amortization expense.

A. PGE Exhibit 204 details the total 2016 amortization expense of $49.7 million, which we summarize in Table 3 below.

Table 3
Amortization
($ in millions)

Amortization Item:	2014 Actuals	2016 Test Year
Software Amortization	$22.2	$38.0
Other Intangible Amortization	$3.2	$7.9
Trojan Decommissioning	$3.5	$3.5
Other Reg Debit Amortization	$22.3	$0.3
Other Reg Credit Amortization	$(0.2)	$0.0
Total Amortization	**$51.0**	**$49.7**

Q. Please explain the amortization of software included in PGE's 2016 amortization expense.

A. Total software amortization is $38.0 million, which includes the amortization of capitalized software and is amortized over a 5 year period (with the exception of the 2020 Vision program which will be amortized over 10 years).

Q. Why is software amortization $15.8 million higher in 2016?

A. The largest drivers for the increase are Next Wave software additions.[2] Next Wave consists of four projects:

1) Maximo, Mobile and Scheduling (Maximo Wave 2);

2) Graphic Work Design;

3) Geographic Information System; and

4) Outage Management System.

Of these four projects, the largest increase in amortization is Maximo Wave 2 at $2.9 million; the other three projects combined contribute approximately $3.8 million to the increase of software amortization expense. Additional software capitalization accounts for the remaining $9.1 million increase.

Q. Please describe Other Intangible amortization.

A. Other Intangible amortization includes hydro relicensing, transmission agreements and miscellaneous other intangible plant amortizations. Generally, these costs are amortized over the life of the new license or over the period of the agreement.

Q. Why is other intangible amortization $4.7 million higher in 2016?

A. The main driver for this increase is amortization of Tucannon transmission credits from BPA.

Q. Please explain the main drivers for the decrease of $22.0 million in regulatory debit amortization.

A. There are two amortization schedules that account for $21.0 million of the decrease. One is the amortization of four large capital projects (PGE Schedule 144) which were deferred and

[2] Next Wave is part of the 2020 Vision program which is discussed in PGE Exhibits 600 and 800.

we are amortizing in 2014 and 2015; the other is the amortization of deferred expenses associated with the photovoltaic incentive rate pilot.

Q. Did PGE make any changes to its Trojan Nuclear Decommissioning Trust (NDT) collection rate in its last general rate case (UE 283)?

A. No. PGE continues to collect $3.5 million annually for the Trojan NDT.

Q. Does PGE recommend any changes to the current $3.5 million Trojan NDT collection rate?

A. Not at this time. We performed an analysis of the annual accrual, updated for the latest Trojan NDT balances, expected rate of return on trust assets, cost estimates, and other parameters. This analysis indicated that no change in the collection rate is needed. Based on this analysis and the considerable uncertainty associated with the spent nuclear fuel at the Trojan site, PGE proposes to maintain the annual accrual rate of $3.5 million.

Q. Is the Trojan NDT overfunded?

A. Yes. In our prior rate case (UE 283) we determined the Trojan NDT was overfunded by approximately $50 million due to the refund we received from the U.S. Department of Energy in 2014. PGE sought OPUC direction and permission to withdraw $50 million and refund that amount to customers. Per Commission Order No. 14-422, PGE was authorized to amortize the $50 million over three years through Schedule 143 beginning in 2015. As discussed earlier in the testimony, PGE is proposing to amortize the refund during 2015 and 2016 as a price mitigation action.

Q. What decommissioning activity is planned at Trojan for 2015 and 2016?

A. No further decommissioning work is planned until after the spent nuclear fuel has been removed from the site. The majority of the structures at the facility have already been demolished. PGE completed the decommissioning and demolition of the Trojan North and Trojan Training buildings in 2014.

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

A. Income Taxes

Q. What is PGE's 2016 estimate of income taxes?

A. PGE's 2016 test period income tax expense forecast is $63.0 million. PGE Exhibit 205 details the test year calculations of income tax expense and provides a comparison to previously authorized 2015 income tax assumptions. This compares to the 2015 utility income tax expense of $52.2 million based on prices approved by Commission Order No. 14-422. The increase in 2016 test year income tax expense compared to current prices reflects an increase of pre-tax book income.

Q. What methodology did you use to establish estimated income tax expense for the 2016 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 are nearly 100% regulated utility activity, this method also conforms to ORS 757.269, which specifies how income taxes are treated for developing prices.

Q. What income taxes does PGE pay?

A. PGE pays income taxes to the federal government, the States of Oregon, Montana, and California, and to local government entities such as Multnomah County.

Q. What are the marginal tax rates for PGE?

A. The federal marginal tax rate is 35.00%, the State of Oregon marginal tax rate is 7.6%, the State of California marginal tax rate is 8.84%, and the State of Montana marginal tax rate is 6.75%.

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

A. PGE's state composite tax rate is 7.21%. The rate is a function of the marginal state tax rates and the respective apportionment factors of taxable income to different state jurisdictions.

Q. Is the state composite rate different than it was in UE 283?

A. Yes. In UE 283, the state composite tax rate was 7.61%. In this proceeding, we have adjusted the figure downward to 7.21% to reflect lower apportionment for California and higher apportionment for Montana based on recent actual results.

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

A. PGE's total composite tax rate for this filing is 39.69% which is the sum of the federal marginal tax rate and the state composite tax rate, less the effect of their interaction, or:

$$35.00\% + 7.21\% - (35.00\% * 7.21\%) = 39.69\%$$

Q. Why did you exclude tax rates from local jurisdictions from the calculation of the composite tax rate?

A. PGE collects Multnomah County Business income taxes through a supplemental tariff to comply with OAR 860-022-0045. As such, we do not include an estimate of the costs as part of our revenue requirement in this proceeding.

Q. Did you include state and federal tax credits in your estimate of income tax expense for 2016?

A. Yes. In the estimate for 2016 income tax expense we include approximately $0.5 million of state Business Energy Tax Credits (BETC), $0.5 million of state pollution control tax credits, and $49.2 million of federal Production Tax Credits (PTC). The BETCs are earned from PGE's Biglow Canyon Wind Farm. The PTCs are earned from PGE's Biglow Canyon and Tucannon River Wind Farms.

B. Taxes Other Than Income and Fees

Q. What is PGE's 2016 estimate of Taxes Other Than Income and Fees?

A. As shown in PGE Exhibit 206, total Taxes Other Than Income are $122.7 million for 2016. This compares to 2014 actual costs of $106.8 million. The individual sources of increased costs from 2014 actuals to the 2016 test year are:

- Franchise Fees: from $41.6 million to $46.8 million;
- Payroll Taxes: from $13.6 million to $14.2 million; and
- Property Taxes: from $49.9 million to $60.0 million.

1. Franchise Fees

Q. What are franchise fees?

A. Franchise fees and privilege taxes are collected by PGE and in turn paid out to Oregon city governments within our service area for the right to operate within their city limits. Based on OAR 860-022-0040, cities may charge up to 3.5% of gross revenue that will be included in PGE's revenue requirement and charged to all customers. Assessments up to 5.0% of gross revenue are allowed, but the incremental fees above 3.5% are identified as privilege taxes and charged to customers through a separate charge on the bill payable only by customers in the assessing jurisdiction(s).

Q. Are franchise fees included in PGE's net to gross factor for calculating revenue requirement?

A. Yes. Consistent with the unbundling requirements of OAR 860-038-0200, we separately itemize the impact of our incremental revenue needs on franchise fees to directly assign all franchise fees to the distribution function. The current franchise fee rate used to determine this revenue-sensitive cost is 2.5471%, which is the three-year average (2012 through 2014) of actual franchise fee expenses. This compares to the rate of 2.5012% authorized in UE 283.

Q. Why have franchise fees increased from 2014 to the 2016 test year?

A. The franchise fee rate was updated to reflect the three year average of 2012-2014 actuals. Franchise fees have also increased due to the impact of PGE's requested revenue requirement increase in this proceeding.

2. Payroll Taxes

Q. What are payroll taxes?

A. Payroll taxes represent local, state, and federal assessments on wages and salaries. The federal components include FICA (Social Security), Medicare, and Unemployment. The Oregon components include Workers' Compensation, Unemployment, and a local withholding for Tri-Met.

Q. How does PGE estimate payroll taxes?

A. PGE estimates payroll taxes by applying an approximate 9.2% 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 2014 to the 2016 test year?

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

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 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. How is the Cost Approach calculated?

A. Cost approach valuation is calculated using the regulatory calculation for rate base with the following major adjustments:

Plant in Service
+ Construction Work in Progress (CWIP)
+ Materials and Supplies
+ Future Use
+ Contributions in Aid of Construction (CIAC)
- Accumulated Depreciation/Amortization
= Net Cost Valuation

CIAC is traditionally subtracted from plant in service to derive rate base. However, when calculating property taxes, any contribution made by customers for bringing electrical service to their property is taxable, because the property, such as a customer line extension, is ultimately owned by PGE.

Q. Are there other adjustments to the Cost Approach?

A. Yes. The Trojan switchyard is still in use and therefore taxable despite the fact that PGE's Trojan assets were previously written off for book purposes. In addition, any amounts included in plant in service or accumulated depreciation related to Asset Retirement Obligations (Statement of Financial Accounting Standards No. 143) are excluded from tax assessment. Lastly, licensed vehicles and deposits on assets not yet onsite are excluded from the cost approach.

Q. What is the second property tax valuation method and how is it used?

A. The second method is the Income Approach. This approach values the utility based on the projected earnings of PGE. The theory underlying this approach is that a prospective buyer would look at the capitalization of the future income stream (cash flow) that the company could produce from its utility property. The value is calculated as net operating income divided by the capitalization rate less growth. Net operating income includes the probable future average annual net operating income from properties that exist on the assessment date.

Q. How is the capitalization rate determined?

A. Cost of capital is the basis of the capitalization rate; however, it should be noted that capitalization rates for property tax purposes vary by state. A high capitalization rate would reflect a lower valued property.

Q. What is the third assessment valuation method?

A. The third method is the Comparable Sales Approach. This method compares similar properties that have sold recently. It is similar to using recent residential home sales in a neighborhood as an indicator of the value of other homes in the same neighborhood. This approach is problematic for large electric utilities due to limited sales activity in the utility industry. Instead, tax authorities estimate sales value by examining the market value of PGE stock and debt. This approach is also difficult to calculate because of the fluctuating nature of stock prices.

Q. Once each of these three approaches determines a value, how are they reconciled to reach a final assessed value for PGE property?

A. In Oregon, the three amounts calculated using these methodologies are reviewed by Department of Revenue personnel and, using the appraiser's judgment, a correlated value is determined. The state then uses the Western States Association of Tax Administrators (WSATA) formula to calculate Oregon's portion of system assessed value. The WSATA formula uses cost, operating capacity, and production megawatt hour factors in each state to estimate the percentage of system value to allocate to Oregon. Montana uses the WSATA formula similar to Oregon. PGE has historically had little presence in Washington, and therefore, the three approaches to value were not used by that state. Washington previously valued PGE property in the state (i.e., percentage of KB Pipeline) using historical cost less depreciation of Washington's assets. With the addition of Tucannon, the valuation method is expected to remain the same as the one currently used for the KB Pipeline.

Q. Can PGE dispute or appeal assessed values determined by each state?

A. Yes and we appeal almost every year in Oregon and Montana. For example, for the 2013/2014 fiscal tax year, PGE disputed the original Oregon assessed value of approximately $4 billion and was able to receive a reduction of $300 million in assessed value. Also, PGE was able to reduce its 2013 Montana assessed value by $6.7 million, which resulted in a $0.1 million reduction in property tax expense. Because of the straight-forward valuation methodology in Washington and the very small amount of property taxes paid to that state (less than $50,000 per year through 2013) PGE has not appealed recent assessments in Washington.

Q. After the states and PGE agree to assessed values, how is the tax liability calculated?

A. PGE provides each state with the allocated cost of all PGE property in each taxing district in each county in the annual report. There are numerous taxing districts within each county. For example, PGE has property located in 17 Oregon counties, but receives over 800 individual property tax bills. The state then apportions the assessed value to each taxing district based on the percentage of PGE property within each district.

Q. How else does PGE manage its property tax liability?

A. Each October, PGE receives Oregon tax bills and pays them on or before November 15th to receive the 3% full-payment discount.

Q. Has PGE used property tax savings incentives for its major construction projects?

A. Yes, for Biglow Canyon, PGE and Sherman County executed a Strategic Investment Program (SIP) property tax abatement, significantly reducing taxes for a 15-year period beginning in 2008. Also, PGE has completed negotiations with Columbia and Morrow counties and has executed SIP property tax abatement agreements for PW2 and Carty.

Q. Does the 2016 estimate of PW2 property tax expense reflect the benefit of the SIP agreement with Columbia County?

A. Yes. With the Columbia County SIP agreement, we expect 2016 property tax expense for PW2 of $1.6 million. Without the SIP, a full year of property tax expense related to PW2 would be approximately $4.4 million.

Q. Does the 2016 estimate of Carty property tax expense reflect the benefit of the SIP agreement with Morrow County?

A. Yes. Property tax expense of $2.4 reflects the benefit of the SIP agreement.

Q. How does PGE estimate property taxes for pricing purposes?

A. As described above, property tax assessed value is determined using three approaches: 1) Cost, 2) Income and 3) Comparable Sales. Since the Income and Comparable Sales methods involve complex estimates of future events, such as projected income, capitalization rates, growth and future stock values, PGE relies on the cost method to estimate property taxes for developing prices.

Q. Why does PGE rely on the Cost Approach for determining future years' assessed values?

A. There is a strong correlation between net book value of utility plant and assessed value. For example, at January 1, 2013, PGE's net book value of utility plant (per 2012 FERC Form 1) was $3.5 billion whereas Oregon's assessed value was also $3.5 billion. For Montana the correlation between assessed value and net book value of utility plant is not as strong due to that state's utilization of the WSATA formula and its assertion that the low book value of the Colstrip plant is not reflective of its real market value. PGE's assessed value of Montana property as of January 1, 2013 was $243 million. Net book value of Montana property as of that date was approximately $137 million.

Q. How is this prospective cost valuation determined?

A. Because Oregon property taxes are assessed on a fiscal year basis, assessed values at January 1, 2015 and 2016 have to be calculated. Starting with the latest actual assessed value for each state, PGE adds an estimate for projected capital expenditures and associated increases in accumulated depreciation.

Q. After estimated assessed value is calculated, what is the next step to determine 2016 property tax expense?

A. The next step is to estimate the average tax rate at which these values will be taxed. Rates may vary significantly depending on bond measures passed and other changes in each taxing district. For example, in Oregon for the fiscal year 2015/2016, county property tax rates range from less than 1% up to 2% of assessed value with a weighted average of 1.349%. For Montana, 2013 county property tax rates averaged approximately 3.523%. Multiplying projected assessed values by these average tax rates produces gross property tax expense.

Q. Are there any other material adjustments that need to be taken into account in determining property tax expense for pricing purposes?

A. Yes. Property tax on major projects with long construction periods and having a year-end balance in excess of $1.0 million needs to be capitalized while the projects remain in CWIP. PGE applies the most recent average tax rate based on actual payments to calculate property tax on these projects. After a project is placed in service, subsequent property tax accruals associated with it are expensed. Many projects, however, are "standard" or "blanket" jobs that are not subject to property tax capitalization. Also, adjustments have to be made for the Biglow Canyon SIP agreement, which requires additional payments in lieu of property taxes paid to Sherman County.

Q. What is PGE's forecast for 2016 property taxes?

A. PGE's forecast of 2016 property taxes is $60.0 million, excluding Carty, an increase of $10.1 million from 2014 actuals. This increase is primarily attributable to PW2 and Tucannon coming online in late 2014.

Q. Are there any other tax related matters not included in your revenue requirement you would like to discuss?

A. Yes. At this time, there are potential additions to the revenue requirement if unfavorable tax treatment results from two pending Oregon Supreme Court cases and possible legislation enacted during the rate case. The potential additions relate to:

- The City of Gresham possibly increasing utility license fees (privilege tax);
- The Oregon Supreme Court anticipated ruling regarding the treatment of wholesale electricity for state income tax apportionment purposes; and
- Various legislation currently under development in the 2015 Oregon legislative session that, if passed, will impact PGE's tax liability.

VI. Rate Base

Q. What is PGE's 2016 rate base and what does it include?

A. The 2016 rate base, excluding Carty, is $3,986.8 million based on projected rate base as of December 31, 2015. PGE Exhibit 207 provides the details of the 2016 rate base, which includes PGE's investment in plant in service, net of Accumulated Depreciation, and Accumulated Deferred Taxes. In addition, the rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's 2016 rate base compare to rate base amounts approved in UE 283?

A. PGE Exhibit 208 shows that the rate base approved in UE 283 is $3,785.4 million. PGE's rate base increases by $201.4 million to $3,986.7 million at year-end 2015. The increase is primarily attributable to several projects related to distribution construction, North Fork Surface Collector, 2020 Vision program, Grassland Switchyard, and Portland Service Center Upgrade. Table 4 below shows the approximate rate base for each.

Table 4
Major Projects Closing in 2015
($ in millions)

Projects	2015
Distribution Construction	$56.1
North Fork Surface Collector	53.8
2020 Vision Program	44.3
Grassland Switchyard	25.5
Portland Service Center	18.0
Total	**$197.7**

Q. How did you develop an estimate of rate base for the 2016 test year?

A. We calculate rate base at December 31, 2015. First, we estimated year-end 2014 embedded plant using actual results as of the end of the third quarter with forecasted closings through year-end. Next, we evaluated 2015 capital additions. Certain larger projects were closed based on specific forecasted closing dates. For example, we forecast the North Fork Surface Collector and certain 2020 Vision projects to close during 2015.

For most capital additions we evaluate CWIP balances using historical experience. We then apply a forecast closing pattern to CWIP to develop plant-in-service estimates from 2015 capital additions. We do not include 2016 plant additions in the base business revenue requirement.

Q. Please briefly describe the North Fork Surface Collector project.

A. The floating surface collector on the Clackamas River will boost the survival rate of fish traveling downstream from the North Fork Dam. This is a project PGE has been designing for seven years and has taken almost two years to build. This project was a requirement of the hydro relicensing settlement agreement which was included in PGE's FERC license for the Clackamas Hydro Project.

As part of our FERC license, the target survival rate for juvenile fish swimming downstream is 97%. Although the existing juvenile fish collector in North Fork Reservoir worked for most salmon species, to reach the 97% goal we had to get more juvenile spring Chinook from the reservoir in the migrant pipeline and into the lower river. The collector achieves that outcome.

The collector is 147 feet long and 60 feet wide and is being built on a steel barge. When complete, all but three feet of the 26 foot depth of the collector will be submerged. A series of engineered pumps and screens will create an attractant flow of water to lure fish inside. We expect this collector to be operational in the fall of 2015.

Q. Is the pre-paid pension asset included in rate base?

A. No. We plan to continue monitoring Docket No. UM 1633, Investigation Into Treatment Of Pension Costs In Utility Rates, and will update rate base depending on the outcome of that docket.

Q. Are there any new rate base items in 2015 relative to PGE's last rate case?

A. Yes. Tucannon and PW2, approved by the Commission in UE 283, will have trailing costs in 2015.

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

A. Yes. The stipulation in the last general rate case (UE 283) required PGE to have a third-party expert conduct a lead-lag study and examine possible double-counting related to materials and supplies. PGE hired the independent consulting firm, Expergy, to prepare the study using actual 2013 results. During the January 6, 2015 workshop with OPUC Staff, CUB and ICNU, Staff expressed comfort with the lead/lag days but not with certain components of the study. For purposes of the 2016 test year, PGE used a hybrid approach of PGE's standard methodology (previously reviewed and approved by the Commission) combined with the lead/lag days yielded by the Expergy study.

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

A. Applying the 3.63% working cash factor to total forecasted operating expenses in 2016 of $1,557.3 million yields the working cash addition to rate base of $56.5 million, which is shown in PGE Exhibit 201.

VII. Carty

Q. What is the annual revenue PGE requires as a result of the addition of Carty?

A. As shown in PGE Exhibit 201, column 5, PGE requires an additional $83.6 million annually for Carty's expected operating costs, net of dispatch benefits, as well as to provide a reasonable return on investment. Carty is discussed in more detail in PGE Exhibit 300.

Q. How did you estimate the operating costs of Carty?

A. We estimated the operating costs on an annualized basis, reflecting costs for a full year of operations. Carty's total O&M costs of $10.1 million and depreciation expense of $14.4 million reflect a full year's costs.

We derived the dispatch benefits of Carty in the revenue requirement by taking the dispatch benefits of approximately $1.0 million for Carty's operations in 2016 and multiplying the benefit by the ratio of 12 month loads to the lesser amount of load during Carty's operating period in 2016. This results in a reduction of $1.6 million in the revenue requirement.

Finally, rate base of $483.7 million for Carty reflects an average balance over the first full year of operation.

Q. Does PGE include property taxes associated with Carty in the Carty revenue requirement calculation?

A. Yes. Annualized property taxes for Carty amount to $2.4 million in 2016. This includes the benefit of $4.3 million related to the Morrow County SIP property tax abatement.

Q. Do you propose a major maintenance accrual for Carty?

A. Yes. PGE proposes a major maintenance accrual for Carty based on the projection of the Long-term Service Agreement (LTSA) expenses and other major maintenance or inspections not covered by the LTSA. Carty's major maintenance contract is described further in PGE Exhibit 300. We propose a levelized amortization amount of approximately $5.4 million that collects those projected expenses over a five-year period. The major maintenance accrual will help smooth the lumpy nature of these costs and result in better matching of cost with revenue. This will also reduce the frequency of price changes by eliminating the need for an annual true-up and prevent excessive over- or under-collection for LTSA and maintenance expenses, ensuring that customers only pay for costs incurred.

Q. Is PGE requesting prices to recover Carty costs effective January 1, 2016?

A. No. As stated above and explained in more detail in PGE Exhibit 1400, we are requesting prices effective with the in-service date of Carty. The annualized fixed costs of Carty should only be minimally affected by the in-service date (e.g., monthly inflation on O&M) and are likely immaterial.

VIII. Unbundling

Q. Have you unbundled the 2016 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 5 below summarizes the unbundled revenue requirement for 2016.

Table 5
Unbundled Revenue Requirement
($ in millions)

Production	$ 1,114.0
Transmission	$ 33.6
Distribution	$ 562.2
Ancillary	$ 5.0
Metering	$ 8.7
Billing	$ 61.1
Other Consumer Services	$ 53.2
Total	**$ 1,837.8**

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. The total unbundled revenue requirement including Carty is presented in PGE Exhibit 210.

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 2016 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 6 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.

IX. 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 in 1985 and a Master of Business Administration with an emphasis in Finance from the University of Wyoming in 1987. In 1990, I became a Certified Public Accountant. I have worked at three state commissions (Wyoming, Texas and Oregon) totaling 12 years of regulatory experience. I also worked at PacifiCorp for nearly three years in Corporate Accounting. I have been with PGE for over seven years and in the Rates and Regulatory Affairs department for over four years, totaling over 20 years of experience.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
201	2016 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 2015
209	Base Unbundled Results of Operations Summary
210	Carty Unbundled Results of Operations Summary

PGE Exhibit 201
2016 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	Base Business			Base Business and Carty		
	2016 Results at 2015* Base Rates	Change for Reasonable Return	2016 Results After Change for Reasonable Return	2016 Results at 2015* Base Rates	Change for Reasonable Return	2016 Results After Change for Reasonable Return
	(1)	(2)	(3)	(4)	(5)	(6)
Operating Revenues						
Sales to Consumers (Rev. Req.)	1,799,009	38,752	1,837,761	1,837,761	83,583	1,921,344
Sales for Resale	-	-	-	-	-	-
Other Operating Revenues	25,138	-	25,138	25,138	-	25,138
Total Operating Revenues	1,824,147	38,752	1,862,900	1,862,900	83,583	1,946,483
Operation & Maintenance						
Net Variable Power Cost	556,895	-	556,895	555,296	-	555,296
Operations O&M	254,802	-	254,802	264,932	-	264,932
Support O&M	239,568	312	239,879	241,524	673	242,197
Total Operation & Maintenance	1,051,265	312	1,051,577	1,061,752	673	1,062,425
Depreciation & Amortization	319,954	-	319,954	334,351	-	334,351
Other Taxes / Franchise Fee	121,754	987	122,741	125,400	2,129	127,529
Income Taxes	48,126	14,858	62,984	47,401	32,047	79,448
Total Oper. Expenses & Taxes	1,541,099	16,157	1,557,256	1,568,905	34,849	1,603,753
Utility Operating Income	283,049	22,595	305,644	293,995	48,735	342,730
Rate of Return	7.101%		7.667%	6.578%		7.667%
Return on Equity	8.769%		9.900%	7.723%		9.900%

* 2015 Rates per approved UE 283 and UE 286

Rate Base						
Plant in Service	8,705,924	-	8,705,924	9,194,174	-	9,194,174
Accumulated Depreciation	(4,219,464)	-	(4,219,464)	(4,226,062)	-	(4,226,062)
Accumulated Def. Income Taxes	(591,970)	-	(591,970)	(590,615)	-	(590,615)
Accumulated Def. Inv. Tax Credit	-	-	-	-	-	-
Net Utility Plant	3,894,490	-	3,894,490	4,377,496	-	4,377,496
Misc Deferred Debits	26,623	-	26,623	26,623	-	26,623
Operating Materials & Fuel	79,458	-	79,458	79,458	-	79,458
Misc. Deferred Credits	(70,321)	-	(70,321)	(71,280)	-	(71,280)
Working Cash	55,913	586	56,499	56,921	1,264	58,186
Total Rate Base	3,986,163	586	3,986,749	4,469,219	1,264	4,470,484
Income Tax Calculations						
Book Revenues	1,824,147	38,752	1,862,900	1,862,900	83,583	1,946,483
Book Expenses	1,492,973	1,299	1,494,272	1,521,504	2,802	1,524,305
Interest Rate Base @ Weighted Cost of Debt	108,284	16	108,300	121,406	34	121,441
Production Deduction	-	-	-	-	-	-
Permanent Sch M Differences	(23,836)	-	(23,836)	(24,911)	-	(24,911)
Temporary Sch M Differences	92,595	-	92,595	97,277	-	97,277
State Taxable Income	154,131	37,437	191,569	147,624	80,747	228,371
State Income Tax	10,124	2,700	12,824	9,655	5,824	15,479
Federal Taxable Income	144,007	34,737	178,744	137,969	74,923	212,892
Fed Income Tax	50,402	12,158	62,561	48,289	26,223	74,512
Deferred Taxes	36,749	-	36,749	38,607	-	38,607
Federal Tax Credits	(49,150)	-	(49,150)	(49,150)	-	(49,150)
Total Income Tax	48,126	14,858	62,984	47,401	32,047	79,448

PGE Exhibit 201
General Rate Case - 2016 Test Year
Capital Structure / Revenue Sensitive Costs
(000s)

Capital Structure:	Amount	Share	Cost	Weighted
Common Equity	N/A	50.00%	9.900%	4.950%
Preferred	N/A	0.00%	0.00%	0.000%
Long-Term Debt	N/A	50.00%	5.433%	2.717%
Total	N/A	100.00%		**7.667%**

Revenue Sensitive Costs:	
Revenues	1.000000
OPUC Fees	0.003750
Franchise Fees	0.025471
O&M Uncollectibles	0.004300
State Taxable Income	0.966479
State Tax @ 6.24%	0.069704
Federal Taxable Inc.	0.896776
Federal Tax @ 35%	0.313871
Total Income Taxes	**0.383575**
Total Rev. Sensitive Costs	**0.417096**
Utility Operating Income	0.582904
Net To Gross Factor	**1.715548**

RSC Gross-Up Factor			1.0347
State Income Tax:			
	Appor	Rate	Weighted
Montana	3.05%	6.75%	0.206%
Washington			0.000%
California	0.35%	8.84%	0.031%
Oregon	91.78%	7.60%	6.976%
State			7.212%
Composite Tax Rate:			**39.688%**
Check:	Fed Tax		35.00%
	State Tax		7.212%
	Tax Shield		-2.52%
	Composite		39.688%

PGE Exhibit 202
Other Revenue Detail
2012 - 2016 Test Year

Account	Description	2012 Actuals	2013 Actuals	2014 Actuals	2015 Budget	2016 Test Year
4500001	Forefeited Discounts	(2,587,422)	(2,758,129)	(3,092,995)	(3,400,000)	(3,400,000)
4510001	Miscellaneous Service Revenues	(2,303,654)	(1,855,439)	(1,716,285)	(1,570,953)	(1,898,601)
4530001	Sales of Water & Water Power	(4,641)	(14,457)	27,627	-	-
4540001	Rent From Electric Property	(1,707,745)	(1,547,136)	(1,302,935)	(1,233,129)	(1,225,341)
4540002	RentFrElecProperty-Joint Pole	(5,698,892)	(5,328,476)	(6,180,231)	(5,823,522)	(5,926,522)
4560001	Other Electric Revenues	(3,838,937)	(3,355,510)	(4,538,748)	(2,998,638)	(2,999,738)
4560003	OthElecRev-FishWildlifeRecrOps	(11,508)	(13,735)	(15,168)	-	13,209
4560004	OthElecRev-SSHG	(229,099)	(174,696)	(148,901)	(174,684)	(135,000)
4560005	OthElecRev-Utility Non-Kwh	(654)	(1,068)	(1,566)	-	-
4560012	OthElecRev-Steam Sales	(1,055,581)	(2,004,226)	(2,494,638)	(2,350,589)	(2,487,289)
4561001	TransRevOthers-Non-Intertie	(1,840,168)	(2,200,277)	(2,344,157)	(2,115,848)	(1,748,125)
4561002	TransRevOthers-Intertie	(5,413,152)	(5,488,767)	(5,683,073)	(5,331,000)	(5,331,000)
5600003	TransOp-IntercoTransStudyRev	(5,091)	(116,809)	-	-	-
Total		(24,696,544)	(24,858,725)	(27,491,069)	(24,998,363)	(25,138,408)

PGE Exhibit 203
Depreciation Detail ($000s)
2012 - 2016 Test Year

Property Group	(1) 2012 Actual	(2) 2013 Actual	(3) 2014 Actuals	(4) UE283 Filed	(5) 2015 Settled	(6) 2016 Forecast
Boardman	19,631	21,317	26,816	28,812	28,812	29,086
Colstrip	4,906	4,907	5,041	5,758	5,758	5,370
Beaver	3,573	3,637	3,668	4,847	4,698	5,705
DSG	346	473	548	495	501	430
Biglow Canyon	38,298	36,618	35,015	33,534	33,498	32,079
Coyote Springs	5,052	4,898	4,792	5,390	5,108	4,940
Port Westward	6,820	6,647	6,520	9,163	8,858	8,470
Port Westward 2			21	13,588	9,491	8,978
Tucannon			718	23,671	23,209	16,626
Hydro	12,418	11,420	11,847	18,924	15,576	18,161
Transmission	9,606	9,854	9,819	9,837	8,616	10,201
Distribution	111,530	114,043	118,604	101,066	95,572	100,163
General Plant	18,567	20,486	25,919	32,457	32,126	36,343
Total	**230,747**	**234,300**	**249,328**	**287,542**	**271,823**	**276,552**
Remove Boardman Amortz	(2,176)	(2,176)	(3,395)	(4,775)	(4,775)	(6,081)
Retail Adjustment				(78)	(78)	(74)
Sunway				79	79	
Adjusted Total	**228,571**	**232,124**	**245,933**	**282,768**	**267,049**	**270,397**

(1) 2012 forecasted depreciation excludes coal car depreciation of 261 and vehicle depreciation of 3,822.

(2) 2013 forecasted depreciation excludes coal car depreciation of 261 and vehicle depreciation of 3,902.

(3) 2014 Boardman forecasted depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study.
2014 forecasted depreciation excludes coal car depreciation of 261 and vehicle depreciation of 4,214.

(4) (5) 2015 Boardman forecasted 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 forecasted depreciation excludes coal car depreciation of 261 and vehicle depreciation of $3,516.

(6) 2016 Boardman forecasted 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 forecasted depreciation excludes coal car depreciation of $261 and vehicle depreciation of $4,187.
2016 Sunway becomes part of base business

PGE Exhibit 204
Amortization Detail
2012 - 2016 Test Year

Item	FERC Account	AWO	2012 Actual	2013 Actual	2014 Actual	2015 Forecast	2016 Forecast
Software Amortization (Intangible)	404.0		15,696,734	18,987,419	22,237,463	34,251,126	38,019,466
Other Intangible Plant (Includes Hydro Relicensing)	404.0		5,850,777	3,067,447	3,162,746	8,006,277	7,893,425
Trojan Decommissioning	407.0	7000000045	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000
ISFSI Tax Credits	407.3	7000000323	2,274,749	-	-	-	-
Independant Evaluator Deferral	407.3		-	297,920	19,569	521,063	-
Other Cities Franchise Fees	407.3	3000000323				(5,544,695)	
Colstrip Common FERC Adjustment	407.3	7000000107	322,140	322,140	322,140	322,140	322,140
Schedule 110 EE Asset Balancing Acccount	407.3	7000000124	918,669	922,052	920,893	938,127	-
AMI Project Office Costs	407.3		1,360,588	85,479	-	-	-
Coyote Springs Major Maintenance	407.3		2,044,272	-	-	-	-
Intervenor CUB Fund 2	407.3		12,574	-	-	-	-
Intervenor Match Fund 2	407.3		12,154	-	-	-	-
Intervenor Issue Fund 2	407.3		33,112	-	-	-	-
Fit Pilot Program	407.3	7000002001	4,808,006	4,997,432	5,051,152	5,067,937	-
Regulatory Deferral Amortz	407.3	7000010741	-	-	15,978,357	19,473,138	-
Residual Balance	407.3		867,739	54,516	-	-	-
Regulatory Deferral (capital Deferral)	407.4	7000010741	(15,094,023)	(16,966,496)	12,556		
2011 Local 408/MCBIT Deferral	407.4	3000000135	(810,052)	(894,556)	(180,181)	209,798	-
Net Trojan Deferral Reclass	407.4	3000000371				(17,088,672)	
Hawthorne Bldg Remediation	407.4	3000000415	(1,200,000)				
PRC Acq net economic pymt	407.4	3000000727	-	-	-	(1,759,000)	-
Gain On Asset Sales	407.4	7000000317	-	-	-	(6,461,737)	-
Int Income PES Note	407.4	7000000319	(264,322)	(16,606)	-	-	-
Coyote Springs Major Maintenance	407.4	7000000322	(3,432,955)				
ISFSI Tax Credits-Used	407.4	7000000324	(110,290)	-	-	-	-
SB 1149 Residual Balance	407.4	7000000335	(90,226)	-	-	-	-
SunWay 3	407.4	7000000727	(45,480)	(45,480)	(45,480)	-	-
Allocated to retail							(38,019)
Total Amortization			**16,654,166**	**14,311,266**	**50,979,215**	**41,435,502**	**49,697,013**

PGE Exhibit 205
Income Tax Summary
(000s)

Income Tax Expense	UE 283/UE 286 2015 Test Year	2016 Test Year
Book Revenues	1,804,544	1,862,900
Book Expenses (including Depreciation)	1,466,155	1,494,272
Interest Deduction	103,020	108,300
Book Taxable Income	235,369	260,328
Permanent Sch. M	(21,951)	(23,836)
Temporary Sch. M	19,811	92,595
Tax Taxable Income	237,509	191,569
Current State Taxes	18,084	13,816
State Tax Credits	(3,009)	(992)
Net State Income Tax	15,075	12,824
Federal Taxable Income	222,434	178,744
Current Federal Taxes	77,852	62,561
Federal Tax Credits	(48,686)	(49,150)
ITC Amortization	-	-
Deferred Taxes	7,914	36,749
Total Income Tax	52,155	62,984
Effective Tax Rate	22.16%	24.19%
Change in Taxes		10,829

Analysis of Tax Change:

Effective Tax Rate Change	2.04%
Book Taxable Income (UE 283)	235,369
Increase in Taxes Due to Higher Effective Rate	4,790
Change in Book Taxable Income (2016 vs UE 283 and UE 286)	24,959
2016 Effective Tax Rate	24.19%
Increase in Taxes Due to Higher Book Taxable Income	6,039
Sum of Tax Impacts	10,829

PGE Exhibit 206
Taxes Other Than Income
2012 - 2016 Test Year

Item	FERC Account	AWO	2012 Actual	2013 Actual	2014 Actual	2015 Budget	2016 Forecast
Payroll Taxes	408.1	Note 1	12,708,261	12,738,533	13,592,277	14,010,383	14,187,311
Property Taxes - Oregon	408.1	4081001	40,650,530	42,575,618	45,345,336	45,245,153	48,972,214
Property Taxes - Washington	408.1	4081002	36,072	41,616	51,839	6,936,288	6,525,576
Property Taxes - Montana	408.1	4081003	3,847,368	4,150,571	4,507,881	4,569,264	4,448,844
Franchise Fees	408.1	4081010, 4081011	42,081,393	41,184,583	41,634,096	41,877,596	46,809,289
Foreign Insurance Excise Tax	408.1	4081012	9,600	9,600	19,184	-	-
Misc. Tax & Lic Fees - Oregon	408.1	4081013	1,311,815	1,287,143	1,368,136	1,394,249	1,394,249
Misc. Tax & Lic Fees - Montana	408.1	4081014	401,367	370,993	327,767	443,500	403,500
Total Taxes Other Than Income			101,046,406	102,358,656	106,846,515	114,476,432	122,740,983

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

PGE Exhibit 207
Rate Base (000s)
Based on Ending 12/31/15 Balance

		12/31/2015 Balance
	Plant in Service	8,705,924
Less:	Accumulated Depreciation/Amortization	(4,219,464)
	Accumulated Deferred Taxes	(591,970)
	Accumulated Deferred ITC	-
Net Utility Plant		3,894,490
Operating Materials and Fuel Stocks		79,458
Deferred Debits		
	Colstrip Common FERC Adj	430
	Glass Insulators	3,143
	Dispatchable Standby Generation	9,082
	UE 197 Generation Maintenance Deferral	2,053
	Major Maint. Accruals (Coyote & PW1&2)	(1,657)
	CET	8,362
	IT	5,210
Deferred Credits		
	Injuries & Damages	(8,106)
	Customer Deposits	(13,269)
	Incentive Adjustment (UE 283)	(9,500)
	Post Retirement Liabilities	(39,376)
	Misc. Other	(70)
Working Capital		56,499
Rate Base		3,986,749

PGE Exhibit 208
Rate Base Comparison
UE 283 vs. 2016 Test Year
(000s)

	UE 283 Test Year	Working Cash Requirements	Thermal Plant Maint. Accruals	Plant Additions/ Depr/Amort	Accum. Def. Taxes (bonus depr., etc.)	Misc. Other	2016 Test Year
Plant in Service	8,124,459			581,465			8,705,924
Accumulated Depr/Amort	(3,823,736)			(395,728)			(4,219,464)
Accumulated Deferred Taxes/ITC	(618,694)				26,724		(591,970)
Net Utility Plant	3,682,029	-	-	185,736	26,724	-	3,894,490
Other Rate Base	47,215		(4,400)			(7,055)	35,760
Working Cash	56,177	321	-	-		-	56,499
Rate Base	3,785,421	321	(4,400)	185,736	26,724	(7,055)	3,986,749

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.)	1,114,003	33,612	562,163	4,950	8,711	61,108	53,213	1,837,762
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	3,552	11,820	14,692	(4,950)	2	4	18	25,138
Total Operating Revenues	1,117,555	45,433	576,856	-	8,713	61,112	53,231	1,862,900
Operation & Maintenance								
Net Variable Power Cost	556,895	-	-	-	-	-	-	556,895
Total Fixed O&M	149,344	9,885	95,479	-	-	-	-	254,708
Other O&M	69,322	4,449	69,826	-	2,137	51,913	42,325	239,973
Total Operation & Maintenance	775,561	14,334	165,305	-	2,137	51,913	42,325	1,051,577
Depreciation & Amortization	144,849	10,887	148,791	-	3,198	7,775	4,454	319,954
Other Taxes / Franchise Fee	42,095	3,237	72,187	-	675	882	3,666	122,741
Income Taxes	(6,360)	5,431	61,792	-	849	341	931	62,984
Total Oper. Expenses & Taxes	956,145	33,889	448,075	-	6,859	60,911	51,376	1,557,256
Utility Operating Income	161,410	11,543	128,780	-	1,854	201	1,856	305,644
Rate of Return	7.67%	7.67%	7.67%	N/A	7.67%	7.67%	7.67%	7.67%
Return on Equity	9.90%	9.90%	9.90%	N/A	9.90%	9.90%	9.90%	9.90%
Average Rate Base								
Utility Plant in Service	4,488,391	322,837	3,724,016	-	43,480	75,404	51,796	8,705,924
Accumulated Depreciation	2,052,062	143,564	1,916,623	-	15,912	66,493	24,810	4,219,464
Accumulated Def. Income Taxes	423,639	32,125	119,705	-	4,276	10,344	1,881	591,970
Accumulated Def. Inv. Tax Credit	-	-	-	-	-	-	-	-
Net Utility Plant	2,012,690	147,147	1,687,688	-	23,292	(1,432)	25,105	3,894,490
Operating Materials & Fuel	66,324	776	12,359	-	-	-	-	79,458
Misc Deferred Debits	11,686	3,312	3,036	-	1,363	3,364	3,862	26,623
Misc. Deferred Credits	(20,000)	(1,898)	(39,560)	-	(719)	(1,518)	(6,626)	(70,321)
Working Cash	34,690	1,230	16,257	-	249	2,210	1,864	56,499
Total Average Rate Base	2,105,390	150,566	1,679,779	-	24,185	2,624	24,204	3,986,749

Included in PGE Exhibit 210
Unbundled Results of Carty Summary
2016 Results at Reasonable Return
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	81,075	-	2,508	-	-	-	-	83,583
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	-	-	-	-	-	-	-	-
Total Operating Revenues	81,075	-	2,508	-	-	-	-	83,583
Operation & Maintenance								
Net Variable Power Cost	(1,599)	-	-	-	-	-	-	(1,599)
Total Fixed O&M	10,130	-	-	-	-	-	-	10,130
Other O&M	1,948	-	369	-	-	-	-	2,317
Total Operation & Maintenance	10,480	-	369	-	-	-	-	10,849
Depreciation & Amortization	14,397	-	-	-	-	-	-	14,397
Other Taxes / Franchise Fee	2,659	-	2,129	-	-	-	-	4,788
Income Taxes	16,461	-	3	-	-	-	-	16,464
Total Oper. Expenses & Taxes	43,997	-	2,501	-	-	-	-	46,498
Utility Operating Income	37,079	-	7	-	-	-	-	37,086
Rate of Return	7.67%		7.67%					7.67%
Return on Equity	9.90%		9.90%					9.90%
Average Rate Base								
Utility Plant in Service	488,250	-	-	-	-	-	-	488,250
Accumulated Depreciation	6,598	-	-	-	-	-	-	6,598
Accumulated Def. Income Taxes	(1,354)	-	-	-	-	-	-	(1,354)
Accumulated Def. Inv. Tax Credit	-	-	-	-	-	-	-	-
Net Utility Plant	483,007	-	-	-	-	-	-	483,007
Operating Materials & Fuel	-	-	-	-	-	-	-	-
Misc Deferred Debits	-	-	-	-	-	-	-	-
Misc. Deferred Credits	(959)	-	-	-	-	-	-	(959)
Working Cash	1,596	-	91	-	-	-	-	1,687
Total Average Rate Base	483,644	-	91	-	-	-	-	483,735

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Carty Generating Station

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Maria Pope
Jim Lobdell

Table of Contents

I. Introduction

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

A. My name is Maria Pope. I am the Senior Vice President of Power Supply and Operations and Resource Strategy at PGE. My qualifications appear at the end of this testimony.

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

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe PGE's new generation resource, the Carty Generating Station (Carty). We provide a brief overview of the integrated resource planning (IRP) process and request for proposals (RFP) process that led to the selection of Carty as the least-cost and least-risk resource. We also discuss Carty's associated costs and construction progress to date. In short, Carty's development continues to be on scope, on budget, and on time.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II: IRP and RFP Processes
- Section III: Carty Generating Station
- Section IV: Carty Project Costs
- Section V: Carty Timeline and Milestones
- Section VI: Qualifications

II. IRP and RFP Processes

A. IRP Process and Identification of Baseload Energy Need

Q. Did PGE identify a need for annual average energy in its 2009 IRP?

A. Yes. In PGE's 2009 IRP, we identified a shortfall in our annual average energy need. As a result of the shortfall, PGE developed an Energy Action Plan to acquire additional energy resources by 2015. A baseload resource, such as a high-efficiency combined cycle combustion turbine (CCCT), comprised a portion of the energy resource additions considered.

Q. Did the Commission acknowledge PGE's 2009 IRP Action Plan?

A. Yes. The Commission acknowledged the 2009 IRP Action Plan, with requirements, in Order No. 10-457 on November 23, 2010.

Q. Did any of the updates to PGE's 2009 IRP change the identified need for a baseload resource?

A. No. Pursuant to Order No. 10-457 and IRP Guideline (3)(g), we filed two updates to our 2009 IRP: the first update in late 2011 and the second in late 2012. In our 2011 IRP update (filed on November 23, 2011), we assessed load and resources in both 2015 and 2016. In our assessment, we accounted for (1) the impact of modest load growth given the slow economic recovery and (2) the extended regulatory approval process and schedule of our RFPs for new capacity and energy resources. In our 2012 IRP update (filed on November 21, 2012), we identified 2016 (compared to the 2015 date in the 2009 IRP) as the likely start year for new baseload resource additions, but our original need for baseload energy remained valid. Specifically, we stated:

> "The current forecast indicates that our portfolio will be roughly in balance as of 2016, as measured against our projected annual average energy requirement and

> after implementation of the Action Plan. One of the key elements of the Action Plan is the addition of a new, high-efficiency gas-fired Combined-Cycle Combustion Turbine (CCCT) of 300 – 500 MW. Absent a new baseload energy resource, we would instead be nearly 400 MWa short. Therefore, we believe that our Action Plan for new baseload energy remains valid. The Company plans to move forward with its current solicitation for new natural gas-fired generation."[1]

Q. Is the development of Carty consistent with the Commission acknowledged 2009 IRP Action Plan?

A. Yes. Carty will provide our customers approximately 441 MW of baseload energy. The development of Carty continues to be on budget, on scope, and on time. We discuss the development of Carty in Section III.

Q. What is PGE's energy load-resource balance after the addition of Carty?

A. Based on PGE's most recent IRP (PGE's 2013 IRP), we expect our energy load-resource balance under normal hydro and wind conditions to be generally balanced and possibly slightly surplus at times, until 2019. At that point, growing energy deficits begin to emerge.[2]

B. Request for Proposals Process and Selection of Resource

Q. When did PGE issue an RFP for baseload energy resources?

A. We began our RFP process in March 2011, and issued our RFP shortly after the Commission's Order No. 12-215.

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

A. Yes. Pursuant to Competitive Bidding Guideline (5), Accion Group served as the IE for the RFP. The IE reported directly to the Commission and its work was directed by the Oregon Public Utility Commission Staff (OPUC Staff or Staff). The IE independently scored all

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[1] Page 4 of PGE's 2012 IRP Update. PGE's 2012 IRP Update can be found at: https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/irp.aspx

[2] Page 3 of PGE's 2013 IRP. PGE's 2013 IRP can be found at: https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/irp.aspx

short-listed bids and submitted closing reports to the Commission after PGE identified the final short list.

Q. How did PGE evaluate the baseload energy bids?

A. PGE assigned each bid a price (600 points) and non-price (400 points) score according to the criteria and scoring methodology described in PGE's RFP.

Q. How did PGE determine the price scores?

A. PGE prepared financial models for all submitted bids. These models calculated a lifecycle economic value for each bid. The final price score was based on the ratio of (1) the bid's total real levelized cost of energy (expressed in $/MWh) to (2) the real levelized cost of the market alternative over the same term.

Q. How was the final short list developed?

A. In addition to the combination of price and non-price scores used to determine the initial short list, PGE and the IE performed a portfolio analysis to inform the development of the final short list. The portfolio analysis calculated total system production costs for a number of realistic and competitive combinations of energy, flexible capacity and seasonal capacity bids. This analysis, in addition to the price and non-price scores, allowed PGE to create a final short list that identified the resources representing the least-cost and least-risk options for our customers and the company.

Q. Did PGE consider submitting any benchmark resources in the RFP?

A. Yes. As we stated in our 2009 IRP and disclosed in the RFP, we intended to submit a bid for a benchmark resource in the RFP.[3] PGE did submit a bid for a CCCT plant at the Carty site.

[3] Page 8 of PGE's 2009 IRP and Page 13 of PGE's Final Draft Request for Proposals in Docket UM 1535.

Q. Did PGE select its benchmark baseload bid?

A. No. PGE selected another bid that was deemed to be the least cost and least risk.

Q. Which bid did PGE select?

A. PGE selected the bid submitted by Abengoa S.A. for the engineering, procurement and construction of Carty.[4]

Q. Did the IE file a final report?

A. Yes. The IE concluded in its final report filed on January 31, 2013 that the RFP was conducted in a fair manner and resulted in a final short list that identified the resources representing the least-cost and least-risk for our customers and the company:

> "…the RFP was conducted fairly, that all bidders were treated in the same manner and the resulting short list of bids is the product of the evaluation process that was developed by PGE with the participation of the IE being fairly employed. The IE believes the short list includes the bids that are the best value considering both price and non-price factors from among all bids presented in the RFP."[5]

On February 14, 2013 the IE filed an addendum to its final report addressing questions submitted by Staff stating:

> "…seeking … 300-500 MW of baseload, natural gas-fired capacity [is] consistent with the acknowledged IRP needs and those needs did not change enough to justify redesigning the RFP categories."[6]

---

[4] A number of affiliated companies are party to the engineering, procurement, and construction agreement: Abeinsa EPC LLC, Abener Engineering and Construction Services, LLC, Teyma Construction USA LLC and Abeinsa Abener Teyma General Partnership.
[5] Page 39 of Accion Group's "Report of the Independent Evaluator" in Docket UM 1535.
[6] Id. at Page 4.

III. Carty Generating Station

A. Technology

Q. Please describe the Carty Generating Station.

A. Carty is a G-class (CCCT), with an overall net capacity of 441 MW (with duct firing).[7, 8] The CCCT configuration combines the output of two turbines. The first turbine uses natural gas to produce electricity and hot exhaust gas. The exhaust gas is then directed to a heat recovery steam generator (HRSG). The HRSG uses the heat from the exhaust gas to turn water into steam, which is then used by a steam turbine to produce additional electricity.

Carty's natural gas combustion turbine is a highly efficient Mitsubishi 501 GAC (air-cooled) combustion turbine with duct firing capability. Mitsubishi has global experience with its G series turbine, and power providers throughout North America have placed orders for the Mitsubishi 501 GAC combustion turbine.

Operating characteristics of a gas-fired plant vary somewhat with temperature and humidity. At 55° F ambient design temperature and 60.4% relative humidity, the net plant heat rate for Carty in combined cycle mode will be approximately 6,688 Btu/kWh when the plant is new and all parts are in perfect condition.[9] Carty's operating characteristics for power cost modeling purposes are more fully described in PGE Exhibit 400.

B. EPC Contractor and Performance Guarantees

Q. Who is the engineering, procurement and construction (EPC) contractor?

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[7] Carty's fired net capacity of 441 MW is a new and clean measurement at 55° F ambient design temperature. Under modeled January conditions, Carty's net capacity is 449 MW.

[8] By adding and igniting additional gas, duct firing increases the temperature of the hot exhaust gas produced by the natural gas combustion turbine.

[9] Under these same conditions, Carty, in combined cycle mode plus duct firing, will have a net plant heat rate of approximately 6,941 Btu/kWh.

A. While we commonly refer to the EPC contractor as Abeinsa, a number of affiliated companies are party to the EPC contract. These companies include Abeinsa EPC LLC, Abener Engineering and Construction Services, LLC, Teyma Construction USA, LLC and Abeinsa Abener Teyma General Partnership. Abeinsa specializes in turnkey projects, and has more than 7 GW (i.e., 7,000 MW) of installed power in conventional generation plants.[10] Abeinsa has hired Sargent & Lundy (S&L) as their design engineer. S&L has designed more than 300 combined cycle and simple cycle power plants.[11]

Q. What plant performance guarantees has PGE secured from Abeinsa?

A. Before PGE accepts the plant as substantially complete, the plant must meet a number of performance guarantees including:

- fired and unfired net plant electrical output,
- fired and unfired net plant heat rate,
- emission levels,
- noise levels, and
- reliable operations at various load levels.

Some guarantees (e.g., emission levels, noise levels, and reliable operations) are "must fix" items and Abeinsa must remedy any problems that cause the plant to not achieve the guarantees. For other guarantees (e.g., fired and unfired net plant electrical output and heat rate), Abeinsa must meet minimum levels, but is liable for damages for differences between the minimum levels and the guarantees.

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[10] A description of Abeinsa's main conventional generation projects can be found at: http://www.abeinsa.com/web/en/nuestras_actividades/ingenieria_y_construccion/energia_/generacion_convencional/index.html

[11] A description of S&L's experience can be found at: http://www.sargentlundy.com/home/fossil-power/combustion.html

C. Equipment Manufacturer and Long Term Service Agreement

Q. Please describe the equipment manufacturer.

A. Mitsubishi Hitachi Power Systems America (MHPSA) will provide the power plant equipment. MHPSA is a leading supplier of equipment and services for the global power generation market. MHPSA's gas turbine experience includes more than 535 installed units worldwide.[12] The company's ultimate parent is Mitsubishi Heavy Industries, Ltd.

Q. Has PGE signed a long-term service agreement for Carty?

A. Yes. PGE and MHPSA signed a long-term service agreement (LTSA) that provides long-term major maintenance services to Carty to ensure ongoing plant reliability. The LTSA is a valuable tool for utilities (like PGE) that can lack the necessary maintenance service expertise for the newer gas and steam turbine technologies. The LTSA provides assurance and predictability of maintenance at a foreseeable cost.

Q. What are the key provisions of the LTSA?

A. The LTSA covers planned maintenance of the gas turbine, steam turbine, and generators with discounts for unplanned maintenance. The term of the LTSA could be as long as 20 years but early contract termination is possible with appropriate true-up fees. The LTSA's annual fee structure is based on a variable fee per fired hour and quarterly fixed fees. The agreement has an escalation rate clause based on the consumer-price index.

The LTSA carries a warranty that addresses all contract-related work for parts and services. PGE will also receive remote monitoring services from an online monitoring

[12] A description of Mitsubishi's turbine experience can be found at: http://www.mpshq.com/technology---experience.html

center located in Orlando, FL. The services also comprise data analysis and evaluation to improve Carty's overall gas turbine performance.

Q. PGE has proposed major maintenance accruals in the past for other thermal plants. Is PGE proposing a major maintenance accrual for Carty?

A. Yes. As discussed in PGE Exhibit 200, PGE is proposing a major maintenance accrual based on the projection of LTSA expenses. We propose a levelized amortization amount of approximately $5.4 million per year for five years that would collect the projected expenses over this period, including major maintenance expenses. This major maintenance accrual would smooth out costs for our customers, and also ensure they only pay for costs incurred.

Q. Is the proposed major maintenance accrual similar to what PGE currently uses for Coyote Springs[13], Port Westward 1 (PW1) and Port Westward 2 (PW2)?

A. Yes. PGE has used a similar mechanism for the expenses at Coyote Springs since 1996 (UE 93). In UE 262 and UE 283, the Commission approved similar treatment for PW1 and PW2, respectively.

D. Transmission Service and Gas Supply

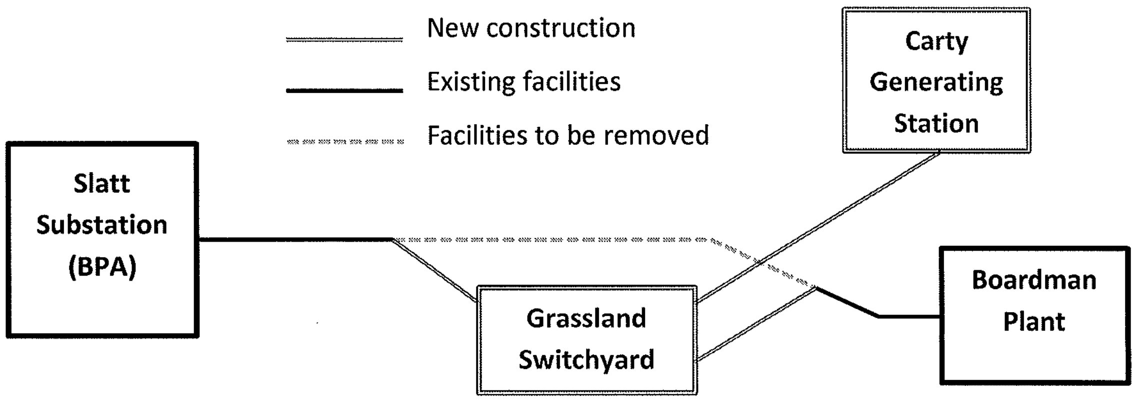
Q. How will Carty interconnect and deliver energy to PGE's customers?

A. Carty will deliver energy to customers under a transmission service agreement granting PGE firm transmission from BPA's Slatt Substation (Slatt). The figure below shows the work underway to interconnect Carty to Slatt. Presently, PGE interconnects the Boardman power plant (Boardman) at Slatt. Abeinsa will construct a 500kV switchyard, known as the Grassland Switchyard (Grassland), to integrate Carty into the existing Boardman-Slatt

[13] Coyote Springs consists of two units. While PGE operates both units, the major maintenance accrual applies only to Coyote Springs Unit 1. Coyote Springs Unit 2 is owned by Avista Corp.

generation lead. Abeinsa will remove a portion of the existing facilities transferring energy between Boardman and Slatt (identified by the dashed line). Carty, along with Boardman, will be connected to Grassland, and a single generation lead will continue to run to Slatt.

Figure 1: Carty Interconnection



Grassland will allow one plant to continue to deliver energy even if the other plant trips offline.

Q. When will Grassland be placed into service?

A. The Grassland switchyard is scheduled to be placed into service by June 2015. This in-service date allows Abeinsa to energize Grassland during Boardman's scheduled outage in 2015. Boardman will begin to use Grassland to serve customers once it is energized. Furthermore, the in-service date is necessary to ensure that Abeinsa can complete Carty's gas-fired testing in November 2015 prior to Carty's planned commercial operation in the second quarter of 2016.

Q. Please describe the plan for Carty's gas transportation.

A. Carty will be fueled with pipeline quality natural gas from a new gas pipeline that connects to the Gas Transmission Northwest LLC (GTN) pipeline. GTN will construct, own, and operate approximately 25 miles of pipeline from the GTN mainline to Carty. PGE has executed a 20-year Firm Transportation Agreement for 75,000 Dth/day of GTN mainline capacity from the Kingsgate hub to the interconnect of the Carty lateral. Carty's gas transportation contracts are more fully described in PGE Exhibit 400.

IV. Carty Project Costs

Q. Is the project within budget and on schedule?

A. Yes. The project is currently within budget and on schedule.

Q. What are the forecast costs associated with Carty?

A. PGE's forecast for Carty consists of the following major categories:

- Gross plant in-service totals approximately $488.3 million. This includes allowance for funds used during construction (AFDC) and property taxes, but excludes the capital cost (and AFDC) associated with Grassland. Grassland will go into service in 2015 and is therefore part of PGE's base revenue requirement forecast.[14] Our estimate for the total capital cost (including AFDC and property taxes) of Carty and Grassland is equal to the total project cost of the RFP bid, which included Grassland.
- Production O&M expenses total approximately $10.1 million in the 2016 test year before consideration of the dispatch benefits in Net Variable Power Costs (NVPC). As described in Section III, Carty's major maintenance accrual annual expense totals approximately $5.4 million. The remainder of production O&M consists of approximately $2.2 million in labor costs plus $2.5 million in non-labor costs.
- Insurance and A&G expenses total approximately $1.6 million.
- NVPC will decline when Carty is added to PGE's system. The details of this cost impact are discussed in PGE Exhibits 200 and 400.

[14] As discussed in Exhibit 200, gross plant in-service for the Grassland switchyard totals approximately $25.5 million.

- Depreciation expenses total approximately $14.4 million in the 2016 test year and are based on the Commission approved depreciation study from Docket UM 1679, Order No. 14-297.
- Property taxes total approximately $2.4 million.

Q. Are there chemical costs associated with Carty?

A. Yes. The chemicals required for Carty's operation include ammonia, similar to the Port Westward 1 plant. The cost of ammonia is not included in plant O&M. Rather, PGE includes the cost of ammonia in NVPC, because the rate of Carty's ammonia use varies directly with Carty's output. The cost and use of ammonia is discussed in PGE Exhibit 400.

Q. What is the net revenue requirement impact of Carty?

A. The revenue requirement for Carty, net of dispatch benefits, is approximately $83.6 million. Details for this calculation are also provided in PGE Exhibit 200.

V. Carty Timeline and Milestones

Q. Has Abeinsa provided a substantial completion deadline for Carty?

A. Yes. The substantial completion deadline is May 16, 2016. Abeinsa will be liable for liquidated damages if the work is not completed by the substantial completion date.

Q. How far along is construction at this time?

A. Construction of the plant is proceeding on schedule. Plant construction is approximately 37 percent complete as of December 31, 2014. We commenced major equipment delivery in August 2014 and have installed all 12 modules of the HRSG units. Work is ongoing for the completion of Grassland and subsequent Boardman interconnection.

Q. What are the construction and testing milestones associated with Carty?

A. Table 1 below lists the construction and testing milestones, both completed and estimated.

Table 1
Carty Milestones

Milestone	Actual/Scheduled Completion
Start of Construction	January 9, 2014*
Start of Boardman Interconnection Work	March 2014*
Start of Transmission Tower Installation	March 2014*
Major Equipment Delivery	Commenced August 2014*
Deliver Gas Turbine	February 2015
Deliver Steam Turbine	April 2015
Grassland Switchyard Complete	June 2015
First Fire	November 2015
Commercial Operation	Second Quarter of 2016

* Asterisk identifies Actual Completion dates

Q. When is PGE requesting Carty be included in customer prices?

A. We request that prices recovering Carty's net revenue requirement become effective shortly after a PGE officer has provided an attestation that Carty has been placed in service in the second quarter of 2016. PGE will update our cost estimates before that time.

VI. Qualifications

Q. Ms. Pope, please describe your qualifications.

A. I received my Bachelor of Arts degree from Georgetown University in 1987 and my Master's degree in Business Administration from the Stanford University Graduate School of Business in 1992. I am currently Senior Vice President of Power Operations and Supply and Resource Strategy, a position I have held since March 2013. Prior to that, I was Senior Vice President, Chief Financial Officer and Treasurer of PGE beginning in January 2009. From January 2006 through December 2008, I served on the PGE Board of Directors. Previous to January 2009, I served as Vice President, Chief Financial Officer at Mentor Graphics Corp., an Oregon-based software company, where I was responsible for multiple departments including the company's financial affairs, corporate development and operations. Before I joined Mentor Graphics in 2007, I served 12 years in a variety of capacities at Pope & Talbot, Inc. and worked previously at Morgan Stanley, Inc. and Levi Strauss & Co.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Net Variable Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Michael Niman
Terri Peschka
Patrick G. Hager

February 12, 2015

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 Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial forecast of PGE's 2016 Net Variable Power Costs (NVPC). We discuss several of the updates to parameters (e.g., ancillary service assumptions) from PGE's NVPC forecast for 2015, as well as modeling changes. We compare our initial 2016 forecast with PGE's final 2015 NVPC forecast and explain why the per-unit expected NVPC have decreased by approximately $0.76 per MWh.

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

A. Our initial 2016 NVPC forecast is $555.9 million, based on contracts and forward curves as of December 4, 2014. This initial 2016 NVPC forecast represents a reduction of approximately $6.4 million relative to our final 2015 NVPC forecast filed in the 2015 NVPC proceeding (Docket No. UE 286).

Q. Will PGE make a separate 2016 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 2016 forecast to which we compare the 2016 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 401 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 fifteen days of this filing (i.e., February 27, 2015). As with PGE's NVPC filings in the 2015 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 12 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; cost of wind day-ahead forecase error to align with the April 1 filing; 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 five sections:

- Section II: MONET Model;
- Section III: MONET Updates and Modeling Changes;
- Section IV: Docket No. UE 286 Stipulation;
- Section V: Comparison with 2015 NVPC Forecast; and,
- Section VI: Qualifications.

II. MONET Model

Q. How did PGE forecast its NVPC for 2016?

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 2015 NVPC proceeding, we include certain variable chemical costs. We exclude some variable power costs, such as certain variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. Based on prior Commission decisions, certain fixed costs, such as excise taxes and transportation charges, are included in MONET. For the purposes of FERC accounting, these items are included with fuel costs in a balance sheet account for inventory (FERC 151); this inventory is then expensed to

NVPC as fuel is consumed. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, 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 2016 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 2016 retail load forecast described in PGE Exhibit 1200.[1] Our forecast is approximately 19 million MWh of cost-of-service energy, or approximately 2,165 MWa, a small increase of 25 MWa from the 2015 test year forecast in Docket No. UE 286.

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 2014 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 2011 through 2014 data by April 1, 2015, consistent with information that would be used in an initial AUT filing for 2016. By that date, we will have processed the 2014 data needed to complete the outage rate calculations. For this filing, we use the same forced outage rates, based on 2010 through 2013 data, from Docket No. UE 286. We will continue to update several of the items included under Schedule 125 as this docket proceeds.

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

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[1] 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).

1. The inclusion of the Carty Generating Station (Carty);
2. Updates to ancillary service assumptions, both the parameters for PGE's thermal resources and MONET's load following logic;
3. Updates to wind integration assumptions to reflect PGE's election of the Bonneville Power Administration (BPA) 30/15 Variable Energy Resource Balancing Service (VERBS) rate;
4. Update to Tucannon's energy forecast to reflect the final PGE commissioned wind study;
5. Update to Colstrip's incremental wheeling costs; and,
6. Update to the latest Pacific Northwest Coordination Agreement (PNCA) Headwater Benefits study in our hydro data.

Q. What is the net effect on PGE's initial 2016 NVPC forecast of these updates and modeling changes?

A. The net effect of these updates and modeling changes is a $3.6 million decrease in PGE's initial 2016 NVPC forecast. Excluding PGE's new resource, Carty, the updates and modeling changes described below result in a $2.6 million decrease in PGE's initial 2016 NVPC forecast.

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 2016 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.

We discuss any forthcoming updates in more detail below.

A. New Resources

Q. Has PGE added any new resources from the 2009 IRP Final Action Plan to MONET for the 2016 test year?

A. Yes. We have added Carty.

Q. Please briefly describe Carty.

A. As discussed in PGE Exhibit 300, Carty is a new combined-cycle combustion turbine (CCCT), with an overall net capacity of 441 MW (with duct firing).[2] Carty is projected to be in service in the second quarter of 2016, and as a baseload resource, contribute to the annual energy needs of our customers.

Q. How did you model Carty in MONET?

A. In MONET, Carty is dispatched when economic to do so. Carty is also available in MONET to provide a subset of ancillary services (i.e., spinning and supplemental operating reserves and load following) within limits established for each plant operating state.[3] For economic energy dispatch, Carty is modeled using the dynamic programming logic in MONET. The dispatch logic optimizes the economic dispatch for Carty across the test period based on monthly heat rates, monthly capacities, variable O&M, chemical costs, forward price curves, and other parameters. We have used this same dispatch logic in previous filings for Port Westward 1, Coyote, Boardman, Colstrip, and Beaver Units 1-7. We describe the dispatch logic in detail in the MFRs.

[2] Carty's fired net capacity of 441 MW is a new and clean measurement at 55° F ambient design temperature. Under modeled January conditions, Carty's net capacity is 449 MW.
[3] The modeling defines operating states (i.e., minimum, full, and full with duct firing) and contains logic to reflect transition constraints between the plant's different operating states.

Q. What costs associated with Carty are modeled in MONET?

A. Similar to other gas-fired plants, such as Port Westward 1, MONET models the costs of natural gas fueling, electric transmission and emissions control chemicals.

Q. Please discuss emissions control chemicals at Carty.

A. Carty uses ammonia for nitrogen oxide control, similar to the Port Westward 1 plant. The use of ammonia at Carty is essentially proportional to the generation of the plant. Consistent with the treatment in Docket No. UE 266, we include the cost of these chemicals in NVPC.

Q. Are the costs of emissions control chemicals included in any other portion of PGE's filing in this docket?

A. No. The costs of emissions control chemicals have been removed from the O&M costs presented in PGE Exhibits 200, 300, and 700.

Q. Please discuss fueling at Carty.

A. PGE will fuel Carty with gas acquired from the AECO trading hub in Alberta, Canada. To transport gas to the Carty station, PGE contracts space on several portions of the natural gas pipeline system. These portions include the TransCanada NOVA Gas Ltd. pipeline system, TransCanada Foothills pipeline system, and the Gas Transmission Northwest LLC (GTN) mainline from the Kingsgate hub to the interconnect of the Carty lateral. On the GTN mainline, PGE has executed a 20-year Firm Transportation Agreement for 75,000 Dth/day of capacity. To move gas through the Carty lateral, PGE executed a precedent agreement for up to 175,000 Dth/day of firm transportation capacity from GTN's mainline to the Carty plant for a 30-year term. Under the precedent agreement GTN will construct, own, and operate approximately 25 miles of 20" diameter pipeline from the GTN mainline to Carty.[4]

Q. Please discuss transmission service at Carty.

A. Carty will deliver energy to customers under a transmission service agreement granting PGE firm transmission from BPA's Slatt substation. In MONET, PGE has modeled 450 MW of BPA point-to-point service for Carty.

Q. What are some of the benefits to NVPC that Carty will provide?

A. Carty will efficiently provide firm power for our customers. In MONET, this benefit reduces NVPC by offseting more costly market purchases. Carty will also contribute to meeting PGE's ancillary service obligations and is capable of providing spinning and supplemental operating reserves and load following.

Q. How will Carty affect PGE's initial 2016 NVPC forecast when it begins operation?

A. Carty's partial year operations in 2016 will decrease PGE's initial 2016 NVPC forecast by approximately $0.98 million.

Q. For the purposes of ratemaking, how did you derive the dispatch benefits assigned to Carty in its revenue requirement?

A. We derived the dispatch benefits assigned to Carty in the revenue requirement by taking the dispatch benefits for Carty's operations in 2016 (i.e., $0.98 million) and multiplying the benefit by the ratio of 12 month loads to the lesser amount of load during Carty's operating period in 2016. This results in a reduction of $1.6 million in the revenue requirement and

[4] If a smaller diameter pipline were used (i.e., 16"), GTN would have needed to build a compressor station. The addition of a compressor station would make the 16" pipeline more costly than the 20" alternative.

ensures that pricing in 2016 will wholly allocate the benefit forecast of $0.98 million to customers during Carty's partial year operations in 2016.

Q. Does PGE plan to change how Carty is modeled in this proceeding?

A. Yes, if available, we may include updates to Carty's plant parameters in the April 1 Filing. With respect to updates for planned maintenance, gas transportation costs, and chemical costs, any updates to Carty will follow the same schedule as PGE's other thermal plants.

B. Ancillary Service Assumptions

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

A. In UE 262, PGE replaced MONET's existing Mid-C hourly dispatch logic with a new methodology. The new methodology improved the logic used to allocate ancillary services while optimizing Mid-C generation. In the new method, PGE included updated operating constraints on PGE's Mid-C projects, accounted for the implicit ancillary service abilities of PGE's Pelton and Round Butte hydro facilities and contracts, and included a functionality that re-dispatches (after the economic dispatch occurs) eligible thermal plants to cover ancillary service needs that are unmet by hydro resources for a given hour. The enhancements resulted in a more accurate dispatch of PGE's Mid-C resources, and accounted for the role that PGE's thermal resources serve in meeting PGE's ancillary service needs.

Q. What updates have been made to the ancillary service modeling in MONET for this filing?

A. PGE updated three items: thermal plant ancillary service abilities, load following reserves, and the load following sort order.

Q. Please describe the update to the thermal plant ancillary service abilities.

A. Previously, the Beaver combustion turbines and Port Westward 2 units were modeled in MONET with ancillary service abilities. As a part of our efforts to prepare for frequent use of sub-hourly scheduling and dispatch, we conducted studies of our thermal resources to determine their cycling capabilities and the costs associated with using them to balance load and variable energy resources. We used the results from these studies to model the ancillary service abilities[5] of Coyote Springs, Port Westward 1, and Boardman.

Q. Why were the cost of cycling studies conducted?

A. PGE plans to use the results from the cost of cycling studies as a wear and tear component cost for economic dispatch of the plants, particularly in the Real Time Dispatch Tool (RTDT) being developed under PGE's Dynamic Dispatch Program (DDP). We provide a brief description of PGE's Dynamic Dispatch Program in PGE Exhibit 403.

The cost of cycling studies will provide valuable operating information to our plant operators and Power Supply and Operations teams. Additionally, refining our assumptions about the ancillary service capability of our various thermal resources results in a more detailed forecast of NVPC (based on average hydro and average weather) as power markets become more granular and we more frequently adjust the power output from our thermal resources to meet system flexibility needs.

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

A. Yes. If updated parameters are available, we will include the updates in the April 1 update filing.

[5] Ancillary service abilities include (1) spinning and supplemental operating reserves and (2) load following.

Q. What effect do the updates to PGE's thermal plant ancillary service abilities have on PGE's initial 2016 NVPC forecast?

A. The updates to our thermal plant ancillary service abilities decrease PGE's initial 2016 NVPC forecast by less than $0.1 million.

Q. Please discuss the update to the load following reserves.

A. In MONET, load following reserve is capacity that can ramp up and down to respond to 5-10 minute trends in system load. Previously, we modeled the load following obligation based on the average of the hourly load changes before and after each hour of the load forecast. PGE is replacing this calculated result with the load following obligation from PGE's Resource Optimization Model (ROM).

On an annual basis, there is little difference between the cost of the ROM load following obligation and the previous load following obligation modeled in MONET. However, because we are updating the wind integration cost modeling in MONET to 15-minute scheduling, using the ROM load obligation ensures PGE can calculate a meaningful following requirement for load net of wind generation ("load-net-wind").

The ROM load data are shaped on actual data from the same historical time period as used for the wind velocity data. Since load and wind correspond to the same period, we are able to account for the relationship that exists between load and wind in the dataset. By accounting for this relationship, we more accurately model the additional following needs that occur when we begin to schedule our wind resources on a 15-minute (rather than hourly) basis. We discuss the load obligation used in PGE's ROM model in more detail in PGE Exhibit 404.

Q. Please discuss the load following sort order update.

A. To allocate the Mid-C load following ability, we sort the hourly load following requirements in each month by an order that is specified in MONET. Previously, the sort order began first with the hour of greatest need, because the system had less ability to provide ancillary services with thermal plants. Due to the expected system changes in 2016 (increased ability for thermal plants to provide ancillary services, reduced Mid-C ability to provide ancillary services, and increased following obligations due to 30/15 wind integration), the sort order was updated to begin with the hour of lowest Mid-C price. This tends to shift the following obligations that are sent to the thermal plants toward the higher priced hours when it is more economical for them to provide the service.

Q. What effect do the load following updates have on PGE's initial 2016 NVPC forecast?

A. Collectively, the load following updates will decrease PGE's initial 2016 NVPC forecast by less than $0.1 million.

C. BPA Variable Energy Resource Balancing Service Election

Q. Can you please briefly explain BPA's VERBS and 30/15 committed scheduling?

A. Yes. Currently, PGE's owned wind resources (Biglow Canyon Wind Farm and Tucannon River Wind Farm) are part of BPA's Control Area. Under its transmission tariff, BPA offers VERBS to customers with variable energy resources (VERs), such as wind, within BPA's Control Area. 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.

Under the 30/15 committed scheduling option, PGE will make four wind schedule changes per hour.[6] PGE will submit 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 2016 NVPC forecast?

A. We use the BPA VERBS Base Service rate for 30/15 committed scheduling in our initial 2016 NVPC forecast.

Q. Did PGE use 30/15 committed scheduling in its 2015 NVPC forecast?

A. No. PGE used 30/60 committed scheduling in its 2015 NVPC forecast, adjusted for an estimate of integration benefits from Port Westward 2 (PW2) during the fourth quarter of 2015 (after PGE's existing committed scheduling election had expired). BPA's 30/60 committed scheduling option was a reasonable basis for the 2015 NVPC forecast because PGE had elected the 30/60 committed scheduling option for BPA's VERBS through September 30, 2015, and BPA had not yet offered election options for the October 1, 2015 to September 30, 2017 BPA rate period. Our adjustment in the fourth quarter of 2015 served as a proxy for the benefits that customers could receive when PGE used its resources

[6] Under the 30/60 service currently used by PGE, we only make one schedule change per hour.

to manage within-hour schedule to schedule changes (i.e., intra-hour variability) from our wind resources.

Q. Did PGE discuss the election of 30/15 committed scheduling with interested Parties?

A. Yes. PGE met with interested Parties on September 15, 2014. At this meeting, we summarized our analysis of the election options, and we provided Parties with background on BPA's interest in settling the generation inputs portion of their upcoming rate case (BP-16).

During UE 286, PGE anticipated the next BPA VERBS election to be in April 2015 for service beginning on October 1, 2015 and ending on September 30, 2017. However, in July 2014, BPA offered a rate settlement to VERBS customers. In its settlement offer, BPA asked PGE and other VERBS customers to make a BPA VERBS election in September 2014 (instead of April 2015). In exchange for the early election, PGE and VERBS customers received several benefits, including no change in VERBS rates from BPA's 2014 rate case (BP-14) levels. PGE and other VERBS customers accepted the settlement offer, making their committed scheduling election by September 18, 2014.

Q. Why did PGE elect to change to BPA's 30/15 committed scheduling?

A. PGE selected 30/15 committed scheduling to implement a step-wise approach toward more frequent scheduling and dispatch of our plants. Under 30/15 committed scheduling we will use our hydro and thermal resources to manage the intra-hour variability of our wind resources on a 15-minute basis. This increased dispatch activity will give our Balancing Authority operators experience in moving the power output across multiple resources (including thermal resources) for system flexibility. This experience is complementary to the within-hour markets that are developing in the region. PGE's election of 30/15 committed scheduling also provides customers with cost savings over BPA's 30/60 committed scheduling because the savings in BPA rate and generation imbalance energy charges are likely to be greater than the increases to PGE's system operating costs.

Q. How was this implemented in MONET?

A. In MONET, we updated the BPA VERBS integration costs to reflect the 30/15 rates. Additionally, we removed the BPA imbalance premium cost because the associated costs are not expected to be incurred under the 30/15 scheduling.

We modeled the additional following needs due to the 30/15 scheduling based on load net wind following burdens from the ROM model. The inputs are discussed in more detail in the MFRs.

Q. Does PGE plan to update this during the proceeding?

A. Yes. PGE plans to update the load net wind following burden to reflect the load forecast in our final filing and as needed during the proceeding.

Q. What effect does this update have on PGE's initial 2016 NVPC forecast?

A. Updating wind integration to 30/15 committed scheduling decreases PGE's initial 2016 NVPC forecast by approximately $2.9 million.

D. Tucannon Wind Farm Energy Forecast

Q. What was the previous source for PGE's estimate of Tucannon Wind Farm's energy forecast?

A. In Docket Nos. UE 283 and UE 286, Parties stipulated to an annual capacity factor of 38.2% for the Tucannon Wind Farm (Tucannon). PGE used monthly and hourly shaping factors sourced from an evaluation of the Tucannon site completed by RES America Development

Inc. We used these shaping factors to spread an annual energy value into values for each month and hour of the year.

Q. What estimate of Tucannon's energy forecast does PGE use in this filing?

A. In our study of the Tucannon site, we requested DNV-GL to carry out an independent analysis of Tucannon's energy production. In this filing, we are using the results from the final DNV-GL wind study. Tucannon's annual capacity factor forecast is 38.2%, which is no change from the annual capacity factor to which Parties stipulated in Commission Order No. 14-318. There are changes in the monthly and hourly shaping factors.

Q. What effect does the update to Tucannon's monthly and hourly shaping factors have on PGE's initial 2016 NVPC forecast?

A. Updating Tucannon's monthly and hourly shaping factors has an insignificant impact, decreasing NVPC by less than $0.1 million.

E. Colstrip Incremental Wheeling Cost

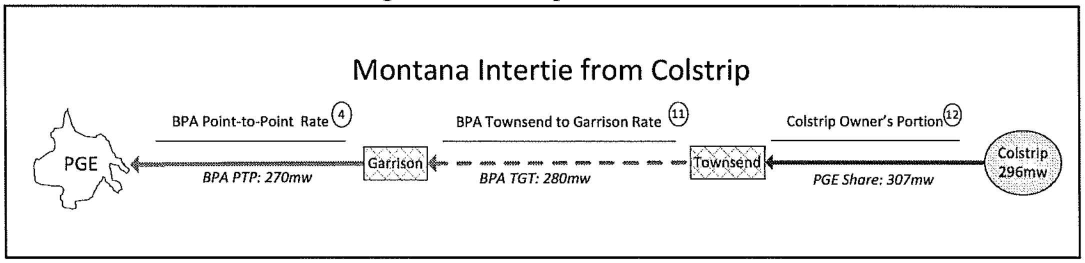
Q. Please describe Colstrip incremental wheeling.

A. PGE brings most Colstrip power into PGE's system using three transmission agreements:

1) The intertie from Colstrip through Broadview and into Townsend. This leg was built by the Colstrip Owners and PGE has approximately 307 MW of rights.
2) The segment from Townsend to Garrison ("The Montana Intertie") is the second leg of the path and was built by BPA. BPA sold transmission rights to the Colstrip Owners based on their Colstrip shares at the time. PGE has approximately 280 MW of rights.
3) A Point to Point (PTP) contract with BPA for 270 MW of transmission rights from Garrison to PGE's System.

Figure 1 below depicts the legs of the path and PGE's transmission rights on each leg.

Figure 1 - Colstrip Transmission



Currently, PGE's 20 percent ownership share of Colstrip Units 3 and 4 yields approximately 296 MW. When Colstrip's output exceeds our transmission rights on the second and third legs of the path, PGE must purchase additional transmission, sell the excess generation to a party at Colstrip, or back down our share of Colstrip.

Q. What was the previous estimate for Colstrip incremental wheeling costs?

A. Prior to a stipulation in Docket UE 286, PGE's forecast for Colstrip incremental wheeling costs under normal operations in the test year was approximately \$0.54 million. To derive this value, PGE assumed its additional transmission need to be a forecast of 13.5 MW on an hourly basis with a single wheel by Northwestern Energy to access other PGE transmission rights. In Docket UE 286 PGE and Parties stipulated to \$0.37 million of 2015 Colstrip incremental wheeling costs for 2015.

Q. Why is PGE proposing to update this estimate?

A. As described above, when Colstrip's output exceeds our transmission rights on the second and third legs of the path, PGE must purchase additional transmission, sell the excess generation to a party at Colstrip, or back down PGE's share of Colstrip. The revised wheeling costs stipulated to by Parties in Docket UE 286 underestimates PGE's incremental wheeling costs, primarily by not accounting for the sales of excess generation to a party at Colstrip or backing down the generation.

In MONET, we assume that all generation can be moved to market and that all market sales and purchases are transacted at the Mid-C price. However, at times where PGE has surplus Colstrip generation and no additional transmission is available to move the generation, PGE's sales at the local Colstrip market are often index-minus sales where PGE sells at a price lower than the Mid-C trading price (i.e., a price discount compared to the regional market). This lost revenue due to the lower price is an opportunity cost attributable to the unavailability of incremental transmission. Therefore, PGE includes the cost of the price discount in its Colstrip incremental wheeling costs estimate.

Q. What effect does the update to Colstrip's incremental wheeling costs have on PGE's initial 2016 NVPC forecast?

A. Updating Colstrip's incremental wheeling costs increases PGE's initial 2016 NVPC forecast by approximately $0.12 million.

Q. Does PGE plan to update Colstrip's incremental wheeling costs for the April 1 update filing?

A. Yes. PGE is reviewing 2014 actuals, and we may update our estimate based on the results of the review. We will also update to reflect changes to transmission tariff rates.

F. Pacific Northwest Coordination Agreement Study Update

Q. Please describe the update to include the new Pacific Northwest Coordination Agreement (PNCA) study.

A. Under the PNCA, the Northwest Power Pool conducts an 80-year regulation study called the Headwater Benefits Study (Study), based on a regulation model whose objective function is to maximize the firm energy load-carrying capability of the Northwest system as a whole. This model considers the loads and thermal resources of regional entities, as well as hydro resources. The model produces a simulated regulation of 80 water years under historical stream flows, which we then use, with a set of adjustments, to develop the average hydro energy inputs to MONET. For this filing, we updated from the 2012–2013 Study to the 2013–2014 Study to establish base average expected outputs for our hydro resources. We then adjusted these base figures using essentially the same adjustment steps used to develop hydro inputs to MONET in prior filings (such as removing PGE hydro maintenance, changing to continuous mode, and adjusting for end-of-study reservoir content).

Q. Which historical stream flow years were used in the 2013-2014 Study?

A. The 2013-2014 Study is based on stream flow data from August 1928 through July 2008. The previous study was based on stream flow data from August 1928 through July 1998.

Q. What effect does the PNCA-related change have on PGE's initial 2016 NVPC forecast?

A. Updating the PNCA study increases PGE's initial 2016 NVPC forecast by approximately $0.43 million.

G. 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; 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 will require updates?

A. Yes. PGE expects to update the cost of wind day-ahead forecast error in the July update filing. Due to the run-time of ROM, the data input process, and the time needed for validation of the inputs and results, we do not anticipate having a final estimate of the updated wind day-ahead forecast error cost in time for the April 1 filing. Consistent with our approach in Docket No. UE 286, we propose to provide the parties of this proceeding with the updated estimate and an explanation of input changes via a letter sent by June 1, 2015. The purpose of this letter is to provide parties with adequate time and opportunity to review the updated estimate before we incorporate the estimate in MONET for the July filing.

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

A. The cost of wind day-ahead forecast error 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.

Q. Has an estimate of the cost of day-ahead forecast error been included in PGE's recent power cost proceedings?

A. Yes. An estimate of the cost of day-ahead forecast error has been included in the NVPC forecast by PGE since the 2008 test year in Docket No. UE 188.

Q. What estimate of the cost of wind day-ahead forecast error do you include in this initial 2016 NVPC forecast?

A. In this initial filing, we use a wind day-ahead forecast error cost estimate of approximately \$0.65 per MWh. This estimate was generated by ROM for Docket No. UE 286.

Q. Are there other items that PGE expects will require updates?

A. PGE may need to include an adjustment for transmission credits. As part of the Tucannon Wind Project, PGE acquired BPA PTP transmission credits. The credits will be paid to PGE over a number of years as offsets to Tucannon's BPA PTP transmission costs. In Docket No. UE 286, parties agreed that the 2015 NVPC forecast would reflect the assumption that PGE will receive twelve months of credits during 2015. In the event that PGE receives less than twelve months of credits during 2015, we will include the difference between the actual amount and forecast amount (but not subject to any interest charges) in the 2016 NVPC forecast.

IV. Docket No. UE 286 Stipulation

Q. What is the status of the workshop on PGE's forward curve creation?

A. In Docket No. UE 286, PGE agreed to host a workshop prior to April 1, 2015 to address market forward curves and the role of hedging in PGE's MONET model. PGE will hold this workshop on March 4, 2015.

Q. Please describe PGE's forward curve methodology.

A. In our initial 2016 NVPC forecast, PGE uses the December 4, 2014 forward curves – both gas and electric – in MONET. Price curves for both natural gas and power are generated by the term power and gas trading desks. PGE determines prices by either (1) bid / ask prices quoted by phone brokers and the ICE trading platform or (2) actual transactions that are reported by phone brokers or occur via the ICE trading platform. These prices may be monthly, quarterly, or yearly depending on the forward time frame.

Monthly pricing is usually available for at least the next twelve to fifteen months, quarterly prices up to two years out, and calendar year pricing beyond that. These data are not necessarily continuous and may not be available every day. At the conclusion of each trading day, risk management verifies power curves and the New York Mercantile Exchange (NYMEX) gas forward curve using third party sources such as end-of-day broker sheets. Our gas curves are basis curves that are additive to the NYMEX forward gas curve. Risk management verifies the basis monthly. Risk management also generates monthly prices from quarterly and calendar year pricing based on current monthly shaping.

Q. Has PGE made any changes to its forward curve creation methodology?

A. No. In this initial 2016 NVPC forecast our methodology is consistent with the forward curve creation methodology used in Docket No. UE 286.

V. Comparison with 2015 NVPC Forecast

Q. Please restate PGE's initial 2016 NVPC forecast.

A. The initial forecast is $555.9 million.

Q. How does this 2016 NVPC forecast compare with the 2015 forecast used to develop NVPC in Docket No. UE 286 and approved in Commission Order No. 14-318?

A. Based on PGE's final updated MONET run for the 2015 test year, the NVPC forecast was $562.3 million, or $30.00 per MWh. The initial 2016 forecast (excluding Carty) is $556.9 million, or $29.29 per MWh. Including Carty decreases PGE's initial 2016 forecast to $555.9 million, or $29.24 per MWh.

Q. Is $555.9 million the amount reflected in PGE's revenue requirement based on Carty's inpact?

A. No. Because the Carty revenue requirement reflects annualized amounts, we increased the dispatch benefit from approximately $1.0 million to $1.6 million. This reduces the final NVPC in our case to $555.3 million for revenue requirement purposes.

Q. What are the primary factors (excluding Carty) that explain the decrease in NVPC forecast for 2016 versus the NVPC forecast for 2015 in Docket No. UE 286?

A. Table 1 shows changes in NVPC by factor between 2016 and 2015.

Table 1
Forecast Power Cost Difference 2016 vs. 2015
($ Million)

Factor	$ Effect*
Hydro Cost and Performance	-5.8
Coal Cost and Performance	3.5
Gas Cost and Performance	6.4
Wind Cost and Performance	-0.4
Contract and Market Purchases	-13.5
Market Purchases for Load Change	7.0
Transmission	-2.6
Total	**-5.4**

* Numbers may not total due to rounding.

A primary factor contributing to the decrease in NVPC is an increase in market purchases that replace expiring contract purchases. For example, PGE's 10-year, 100 MW fixed price power purchase agreement (PPA) with TransAlta will expire in 2016. PGE executed this fixed price PPA with TransAlta as an action item pursuant to our 2002 IRP Final Action Plan.[7]

The decrease in NVPC attributable to the market purchases described above is partially offset by the slight net increase in our resource (i.e., hydro, coal, gas, and wind) costs and the costs associated with our market purchases to meet increased load. As we discussed in Section III of our testimony, our load forecast for cost-of-service energy is approximately 2,165 MWa, an increase of 25 MWa from the 2015 test year forecast in PGE's most recent NVPC proceeding in Docket No. UE 286.

[7] Page 30 of PGE's 2013 IRP. PGE's 2013 IRP can be found at: https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/irp.aspx

VI. 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 power cost forecasting, new resource development, least-cost planning, and avoided cost estimates. 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. 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. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
401	List of MFRs per OPUC Order No. 08-505
402C	February 12 Initial Filing MONET Output Files and Assumptions Summary
403	Dynamic Dispatch Program
404	Load Following Obligation in PGE's Resource Optimization Model

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 402C

Confidential

Dynamic Dispatch Program

PGE has committed a significant number of employees to work with software providers and PricewaterhouseCoopers on multiple projects (many beginning prior to 2014) that will enable PGE to make frequent use of sub-hourly scheduling and dispatch. These projects fall under a project plan known as the Dynamic Dispatch Program and include:

1. *Plant Data (PI) Consolidation*: PGE has completed an effort to consolidate its generation data in order to provide a central repository of data that can be easily extracted for operations and analytical work.

2. *Cycling Cost Studies*: PGE conducted studies on its thermal resources to determine their cycling capabilities and the costs associated with using them to balance load and variable energy resources (VERs). The results can be used as a wear and tear component cost for economic dispatch of plants in the Real Time Dispatch Tool described below.

3. *AGC Equipment Installation*: Automatic Generation Control (AGC) allows plants to be remotely controlled. PGE has installed AGC telemetering equipment at the appropriate thermal plants in order to increase their dispatch efficiency while balancing load and VERs.

4. *Real Time Dispatch Tool*: PGE is developing a tool that can simultaneously optimize the PGE system for reliability requirements and economic dispatch of the plants. This will support PGE's ability to (a) integrate VERs, (b) schedule resources sub-hourly, and (c) automatically dispatch plants more efficiently to meet system needs. PGE plans to complete this tool in the second quarter of 2015.

Load Following Obligation in PGE's Resource Optimization Model (ROM)

In ROM, PGE projects its 2016 load and load following reserves by employing a two-step process using 2005 actual load and load following reserves data.

Step 1 - Realign Days of Week

PGE developed the 2016 load and load following reserves from 2005 data by first aligning the 2005 actual data days of the week with the 2016 days of the week. Because January 1, 2005 fell on a Saturday and January 1, 2016 falls on a Friday, we used the first Friday of January 2005 (January 7th) for Friday, January 1st, 2016. We then used Saturday, Jan. 8th, 2005 for Saturday, Jan. 2nd, 2016, and so on. This step is important because the load and wind data must correspond to the same days for consistency in deriving the "load net wind" concept.

Step 2 - Escalate 2005 to 2016

With the realigned 2005 data we scaled up the load to 2016 levels by an escalation factor equal to the percentage increase from PGE's 2005 average annual actual load to PGE's 2016 average annual forecast load. The realigned 2005 load following reserves are then adjusted by a scaling factor to make sure the 2016 load following reserves meet the same level of reliability as the 2005 actual load following reserves. We then used the realigned and scaled data to develop the projected 2016 "load-net-wind" forecast and the associated reserve obligation in the model.

UE 294 / PGE / 500
Barnett – Jaramillo

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Arleen Barnett
Jardon Jaramillo

February 12, 2015

Table of Contents

I. Introduction

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

A. My name is Arleen Barnett. My position is Vice President, Administration. My responsibilities include establishing compensation policy and employee policies, improving PGE's work environment, managing employee recruitment, development and retention, employee relations, overseeing safety and health programs, and overseeing Business Continuity, Security, and Records Management.

My name is Jardon Jaramillo. My position is Director of Compensation and Benefits in the Human Resources Department.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony presents and explains PGE's compensation costs for the 2016 test year and describes the changes to our compensation policies and plans since 2013. Total compensation costs include base wages and salaries, incentive pay, and employee benefits. We also present and explain PGE's proposed pension cost recovery.

Q. What are PGE's expected total compensation costs in 2016?

A. PGE forecasts approximately $331 million in total compensation costs for 2016, with the increase relative to 2014 driven primarily by wages and salaries and medical costs. Table 1 summarizes the costs.

Table 1
Estimated Total Compensation Costs ($Millions)

Component	**2014 Actuals**	**2016 Test Year**
Wages & Salaries*	$213.1	$235.4
Incentives*	$21.2	$9.9
Benefits	$78.8	$85.6
Total Compensation	**$313.1**	**$330.9**

** 2016 amounts exclude Carty Generating Station (Carty).*

The increase in forecasted wages and salaries from 2014 to 2016 is due to market-driven wage and salary adjustments and increased labor requirements needed to meet PGE's business and customer related goals ($22.4 million). Benefits reflect continued increases in medical premiums ($6.4 million). These increases are partially offset by PGE's incentive request, which represents a reduction of $11.3 million from 2014 actuals.

Q. What is PGE's total compensation philosophy?

A. PGE's philosophy is to provide compensation sufficient to attract and retain highly qualified employees necessary to provide safe and reliable electric service at a reasonable cost. At the same time, PGE actively controls costs by targeting our compensation program attributes and costs to reflect market median conditions.

Q. What major challenges influence the development of PGE's compensation philosophy?

A. As in the past, PGE continues to face three significant challenges:

(1) Recruiting;

(2) Rising health care costs; and

(3) A large percentage (approximately 40%) of our workforce is close to (or at) retirement age, creating recruitment and knowledge transfer challenges.

A. Recruiting

Q. Please describe the first challenge – recruiting.

A. PGE continues to face significant challenges in recruiting and hiring that are common to the industry. Currently, PGE's major recruiting challenges are in the areas of engineering, IT security, senior analysts, and skilled trade positions such as metermen and power plant control operators. The market is very competitive for skilled professionals in those fields and potential employees tend to have already been gainfully employed and, in most cases, have long tenure. Additionally, at PGE a large number of these positions are occupied by employees who are nearing retirement, adding pressure to PGE's recruiting efforts. With continued improvement in the job market, there is added pressure to not only attract the necessary skill sets needed at PGE, but also to retain these employees. As seen below in Table 2, hiring for 2014, consistent with trends seen in 2013, is at far higher levels than those seen in 2012 and earlier due to an increased number of retirements and shorter tenured employees leaving for other opportunities. With an improving economy and as changing technologies require new, in-demand skill sets, we expect our recruiting challenges to continue.

Table 2
Position Requisitions

Year	Total Requisitions
2010	459
2011	460
2012	494
2013	612
2014	601

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

A. In difficult to fill positions, PGE frequently enlists the services of contingency-based search firms and may offer wages above the mid-point of our pay-guides, in addition to other increased benefits. More recently, the shortage of highly skilled professionals has resulted in PGE employing more individuals on work visas and has led PGE to rely more heavily on attracting and recruiting talent outside of the local market, further increasing hiring costs. Fortunately, PGE continues to be seen as an employer of choice for many people, which has helped us fill part-time and entry-level positions. PGE also continues to support employee development through educational assistance, mentoring and cross-trainings, which help to fill some senior level positions internally. We also have a summer hire program that helps to develop entry-level engineering, business, and other professional candidates. Additionally, PGE engages in proactive hiring strategies through job fair and college campus outreach, online tools and research, and database management.

Q. How are PGE's challenges with recruiting affecting its total compensation costs?

A. The increased difficulty in finding and retaining qualified workers to fill vacant and new positions is leading to a rise in PGE's hiring costs, increasing our unfilled positions, and placing undue strain on the organization. While PGE has had a difficult time in filling certain highly specialized positions in 2013 and 2014, these positions remain vital to the organization. We fully expect to hire qualified individuals for our unfilled positions and those requested for 2015 and 2016.

B. Health Care Costs

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

A. As we discuss below in Section IV, medical and dental costs continue to rise each year nationwide. According to a report from the Centers for Medicare and Medicaid Services (CMS) Office of the Actuary, health spending is forecasted to grow at an average annual rate of 6.0% from 2015-2023.[1] This growth is 4.1% greater than the average annual All Urban Consumer Price Index over the same period. Additionally, as PGE's annual premiums are based in part on prior usage and employee demographics, there will be higher increases in health care costs as PGE's workforce matures.

Q. How does PGE combat the second challenge – rising health care costs?

A. PGE negotiates and implements new plans that lower expected costs. For example, since we implemented our high deductible health care plans for Providence (2012) and Kaiser (2013), we have seen a noticeable shift in employee enrollments to these plans, which has lowered company-paid healthcare costs in recent years. PGE also offers strategic wellness programs designed to reduce long-term costs by lowering employee health risk factors. In addition, PGE continually looks at program redesigns that ensure that employees receive a variety of competitive health care options, while keeping costs at or below the market median. Finally, as health plan costs rise, because employees share in these costs, they also realize an increased burden, aligning their interests with those of PGE's to minimize health care costs.

Q. Are rising health care costs having a greater effect on PGE's total compensation costs than in the past?

A. Yes. In recent years, PGE has been able to implement plan redesigns and cut administrative costs, helping to keep our health premium increases below the market average. With no additional redesigns for 2015 and 2016 (allowing PGE to realign its health benefit offerings with the market median), external industry-wide factors outside of PGE's control are accelerating the cost of health care premiums.

[1] http://kaiserhealthnews.org/news/health-costs-inflation-cms-report/

C. Replacing a Retirement-Eligible Workforce

Q. What challenges do you face with a retirement-eligible workforce?

A. Over 30% of PGE's current workforce will be eligible to retire (i.e., be at least 55 years of age and have at least five years of service) by the end of 2016. With improved economic and market conditions, PGE has seen an increased number of retirements over the last three years. In 2010 there were 54 retirements; in 2012 this number nearly doubled to 102 retirements; in 2013 the number peaked at 126; and in 2014 the number slightly decreased to 106. While based on demographic data, the retirement wave appears to have crested, early indicators show that 2015 will remain elevated and we expect the number of retirements to remain high for a number of years. More importantly, because a large portion of retirement-eligible employees work in highly specialized, senior level positions, these retirements place large strains on PGE's operations and recruiting efforts. In addition, as other regional and national utilities from which we often draw talent from and local industries with technical professionals have similar retirement situations, the market for skilled professionals is becoming increasingly competitive.

Q. What are some examples of PGE's critical positions?

A. Examples of our most critical positions are specialized utility positions such as transmission and reliability specialists and engineers, standards and electrical engineers, senior-level skilled crafts persons such as line and substation technicians, Information Technology (IT) professionals, and senior-level utility analysts and specialists.

Q. How is PGE responding to the challenge of replacing retiring employees?

A. PGE continues to recruit externally as well as train internal employees (through our cross-training, educational assistance, and mentorship programs) to fill vacancies in positions that have a high impact on the organization, have long learning curves, and are hard to fill. PGE has also developed and implemented a strategy (critical workforce-funding program) to assist with the transfer of critical institutional knowledge from the exiting retiree employee to the newly hired replacement. The critical workforce-funding program, also discussed in PGE Exhibit 600, provides labor-funding dollars to departments that successfully demonstrate they have a departing employee with knowledge and skills that are not easily transferable and are critical to PGE's successful operations. With this targeted funding, departments can recruit and train a replacement well before the current employee leaves, allowing for comprehensive one-on-one training and knowledge transfer. In addition, we continue our workforce development through the support and involvement in regional engineering programs, development of skilled trades, and outreach efforts in educational institutions to develop the current and future pool of workers.

II. FTEs and 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 employees (FTEs) 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. 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.[2] Table 3 provides PGE's actual total FTEs (excluding overtime) for 2014 and forecast for 2016. Additional detail can be found in PGE Exhibit 501.

Table 3
Full-Time Equivalents

PGE FTEs (straight time)	2014 Actuals	2016 Test Year*
Administrative and General (A&G)	348.1	363.1
Information Technology	234.8	248.8
Customer Service/Accounts	484.9	486.9
Generation	495.8	537.0
Transmission & Distribution (T&D)	919.7	938.5
Total FTEs**	**2,483.4**	**2,574.3**

**2016 FTEs are net of PGE's pre-filing adjustments and exclude Carty, which is discussed separately in PGE Exhibit 300.*

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

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

Q. Will PGE need additional employees between 2014 to 2016?

A. Yes. Overall, we will need 91 additional FTEs. However, this figure includes 10 FTEs at Boardman reflecting the additional 10% share increase related to the Power Resources Cooperative transaction, as approved in Commission Order No. 14-422. Net of this addition, the overall change in FTEs is approximately 81.

Q. Can you explain why PGE needs these additional FTEs?

A. Yes. Table 4 below provides the change in FTEs, a brief explanation, and a reference to a detailed explanation in PGE's filing.

Table 4
Change in FTEs from 2014-2016

Area	Change in FTEs	Explanation	Reference
A&G	15.0	Emergency management, compliance, and support services	Exhibit 600
IT	14.0	IT application support and IT security	Exhibit 600
Cust Svc/Accts	1.9	Emerging technologies and Smart Grid	Exhibit 900
Generation	31.2	Gas, hydro, and wind plant operations	Exhibit 700
Boardman 10%	10.0	PRC Share of Boardman	Exhibit 700
T&D	18.8	Off-shift crews, Smart Grid, and distribution engineers	Exhibit 800

Q. Please describe how PGE determines the second component, the market-based pay structure.

A. PGE routinely 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 where the mid-point for each position classification lies. 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. 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, PGE employees' 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 2014, we compared our hourly non-union and salaried non-officer positions with the market. Our study showed that PGE's wage and salary structure is highly correlated 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 forecasted increase in total wages and salaries?

A. Based on the market surveys, Bureau of Labor Statistics Data and including the new FTEs for 2015 and 2016, PGE forecasts a 5.1% average annual increase in overall wages and salaries from 2014 to 2016. Table 5 summarizes total wage and salary costs for 2014 and 2016.

Table 5
Total Wages & Salaries ($000)

PGE Wages & Salaries (straight time)	**2014 Actuals**	**2016 Test Year***
Administrative and General	$57,817	$63,966
Customer Accounts	$24,718	$26,657
Customer Service	$8,539	$9,941
Generation	$43,858	$50,064
Transmission & Distribution	$78,132	$84,807
Total Wages & Salaries**	**$213,064**	**$235,434**

**2016 amounts are net of PGE's pre-filing adjustments and exclude Carty, which is discussed separately in PGE Exhibit 300.*

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

Q. Has PGE made any adjustments to the 2016 FTEs and wages and salaries?

A. Yes. To account for vacancies and/or unfilled positions, which have increased due to higher levels of turnover, retirements, and an increase in difficult-to-fill positions, PGE has lowered its base budget wages and salaries by $7 million; an increase of $2 million from PGE's adjustment in UE 283. In addition, PGE has included a $1 million adjustment to reflect on-going savings expected from myTime, PGE's time collection system and for non-FTE related budget to actual variances such as lower salaried employees replacing higher salaried employees. The adjustment for vacancies and/or unfilled positions translates into a 74.9 overall FTE reduction, whereas the non-FTE related adjustment is strictly an adjustment to wages and salaries, not FTEs. Additionally, for purposes of reducing our request in this case, there is a wage escalation reduction made to employee wages of approximately $790,000.

III. Incentives

Q. What is incentive pay?

A. While incentive pay shares characteristics in common with bonuses, PGE's incentive pay is different from a bonus because of an "at risk" component. 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. Incentive pay places a portion of employee pay at risk, making it dependent on their performance and quality of output.

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, 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 part of PGE's total compensation, incentive pay is very important; it allows PGE to remain competitive in the labor market and encourages employee performance and productivity. High performing employees benefit the company and customers when they are operating efficiently and effectively and are engaged in the work they are performing. PGE's incentive programs align employee goals with shared customer and company goals of striving to keep costs low, improve customer satisfaction, and preserve PGE's financial stability.

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

A. Incentive pay comprises approximately 7.0% of PGE's 2016 total compensation costs. However, the amount of incentive pay for which we are requesting recovery represents approximately 3.0% of PGE's 2016 total compensation. Table 6 below provides a detailed forecast for 2014 and 2016.

Table 6
Total Incentives ($000)

Incentives Plans	2014 Actuals	2016 Test Year*
Performance Incentive Compensation	$7,883	$5,263
Annual Cash Incentive	$6,620	$3,355
Stock (long-term incentive plan)	$5,917	$1,108
Notables and Miscellaneous	$807	$154
Total Incentives	**$21,227**	**$9,880**

**Amounts reflect PGE's test year request excluding Carty.*

Q. Did you exclude a portion of incentive plan costs from this case?

A. Yes. We removed 100% of the Officer Long-term Incentive Program costs and 50% of the cost of all other incentives plans. These adjustments are reflected in the 2016 forecast provided in Table 6.

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 fully benefit customers, provide reasonable incentive to both attract and retain qualified individuals, and to achieve corporate goals. This minimizes turnover, increases efficiency, and produces positive financial results – all goals that directly and positively impact PGE's costs to customers. Although we have made these reductions in this filing, we still believe that all of our incentive costs are appropriate.

A. Performance Incentive Compensation

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

A. The PIC Plan is PGE's broad-based incentive program for most non-bargaining employees. The PIC plan rewards eligible employees with cash payments for performance tied to results that support PGE's Strategic Intent[3] 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 customer-focused goals:

- Individual or Team Scorecard Goals: These scorecard goals are designed to stretch performance and promote individual growth and development, while aligning with corporate operational goals (e.g., efficiency, operational standards). 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 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.

[3] PGE's Strategic Intent is a framework for sustainably growing PGE's business, while delivering value to customers through innovative solutions that meet their current and future needs.

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 customer-focused goals described below. The scores for the first three goals are weighted and determine 50% of the total payout awarded. The final goal (financial performance) is the other 50%. ACI goals are:

- 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 Accounts. 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.
- 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.

Q. Have there been any recent changes to the ACI plan?

A. Yes. Beginning in 2013, the weighting of the customer satisfaction, electric service power quality and reliability, and generation availability goals make up at least 50% of the overall plan goals. Because of this change in design we have included 50% of all ACI costs in our total test year incentive costs for this rate case. This is consistent with OPUC Order No. 97-171, a US West Communications (USWC) rate case, which states in part:

> "If in a future rate case USWC submits employee incentive plans with goals that benefit both ratepayers and shareholders, we will include those expenditures in revenue requirement."[4]

Additionally, PGE increased the overall customer satisfaction target by 5%. We believe it is important for our incentive plans to directly support 1) PGE's strategic direction, 2) our commitment to our core principles and, 3) continuous improvement. By changing the

[4] OPUC Order No. 97-171, p. 74

payout structure and increasing the goal of our customer satisfaction metric, PGE rebalanced the operational goals within the ACI program, further encouraging our employees to improve their daily processes and PGE's overall efficiency. Customers benefit from lower expenses and a more efficient company, while the expected higher net income helps PGE to achieve and maintain a competitive stock price and access to capital. Copies of the most recent incentive plans are included in our work papers.

Q. Have there been any other changes to PGE's incentive plans?

A. Yes. As mentioned above, PGE has begun using an EPS target to measure the Financial Performance component of its incentive plans, as it aligns with industry standards and provides an accurate evaluation of PGE's performance. All other plan components used in 2013 remain in effect.

Q. What new plants are included in PGE's incentive plans for 2016?

A. Tucannon, Port Westward 2, and Carty are included for 2016 and will have plan designs that mirror PGE's successful incentive plans at Biglow Canyon, Port Westward, and Coyote Springs. We have found these plans to be effective in motivating employees to pursue efficiencies, enhance their professional development, and maintain a high level of operations.

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."[5]

PGE forecasts approximately $1.1 million for the 2016 total long-term incentive expense.

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 2016 forecast for Notables is $0.3 million, but our request is $0.15 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 ensure 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 2016 test year.

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

A. No. PGE has removed all Boardman-related incentive costs from this filing because, beginning in 2016, employees working at the Boardman Plant will be eligible only for the Boardman Retention/Reliability Plan, recovered separately through Schedule 145.

[5] OPUC Order No. 06-356, p.1.

IV. 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 among programs, employee groups, PGE and the market. As with the other two compensation components (wages/salaries and incentives), PGE compares our benefits programs to the market and targets prevailing 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 is sufficient to attract and retain quality employees. We do note, however, that some hard to fill positions may require additional costs in order to fill them.

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

A. There are four major components: health and wellness, disability and life insurance, post-retirement, and miscellaneous benefits. These components are also typical parts of our competitors' offerings. We project 2016 employee benefit costs of approximately $86.4 million. As shown in Table 7 below, PGE's total benefits costs are expected to increase 4.7% from 2014 to 2016 on an average annual basis, driven primarily by health care premium increases. This and other drivers are discussed in more detail below and in Section V.

Table 7
Total Benefits ($000)

Benefits Compensation Component	**2014 Actuals**	**2016 Test Year****
Health and Wellness	$39,145	$45,687
Disability and Life Insurance	$3,021	$4,405
Post-Retirement	$35,177	$33,955
Miscellaneous Benefits	$537	$920
Benefits Administration	$909	$639
Total Benefits*	**$78,789**	**$85,606**

**Numbers may not sum due to rounding.*
***Test Year benefits reflect increases for Carty employees.*

Q. How is PGE mitigating the increases in benefit costs?

A. PGE has used several methods to mitigate costs including 1) negotiating with vendors for favorable contract terms; 2) modifying benefits plan structures to track market practice; 3) using programs that encourage a healthy workforce; and 4) proactive investment strategies that reduce required company funding.

Q. Can you provide examples of such actions by PGE?

A. Yes. In 2012, we switched vendors for our Medicare supplement plan, resulting in lower company contributions to the plan, saving approximately $0.5 million for 2015. Also, beginning in 2013, PGE began investing a portion of its Health Reimbursement Account (HRA) asset balance, which will lower the company contributions into this account. In addition, as we noted previously, when health care premiums rise, PGE employees share the increased cost, which mitigates the increase.

PGE also redesigns and adjusts program features to help control costs through shifting a greater share of the burden on to employees. For 2014, the redesign included doubling the employee deductible for Providence plans and increasing the co-insurance. PGE also offers high deductible health plans (HDHPs) through Providence and Kaiser that benefit both PGE and employees through lowered premiums (reducing both PGE's and employees' monthly premium costs). With these changes and previous redesigns, PGE's health care costs only increased by approximately 2% annually from 2012 to 2014. While PGE is forecasting a sharper increase in its health care costs for 2016, our extensive program changes and redesigns over the last five years continue to keep costs lower than they would be otherwise.

PGE also compares outside services and insurance to our own in-house capabilities and self-insurance. As a result, in 2011, PGE moved to an in-house health and welfare administrative system that continues to save $0.3 million annually.

Finally, PGE invests in internal health and wellness programs to help identify and lower health risk factors that reduce long-term medical issues and reduce plan costs. We provide tools and/or referrals for employees identified as high risk regarding health issues during our health screenings. These screenings identify medical risks such as diabetes, heart disease, high cholesterol, and high blood pressure. PGE's medical vendors also provide and encourage participation in wellness programs and disease management programs. In addition, PGE's Energy4Life program sponsors a series of events throughout the year that promote healthy living and active lifestyles. Some examples of these are Healthy Brown Bags, Bike Commute Challenges, Hydration Challenges and Healthy Trails where employees record healthy practices such as exercise minutes, produce servings and sleep. These programs are designed to reduce major medical events, which keep our medical premiums lower than they would otherwise be.

Q. Please explain why medical and dental benefits costs increased approximately $6.4 million from 2014 to 2016.

A. Medical and dental costs continue to rise faster than inflation each year nationwide, not just in the Northwest or at PGE. Medical and dental plan premium increases for PGE's non-bargaining employees are detailed in Table 8 below. The CMS Office of the Actuary are forecasting that growth in health spending will outpace the All Urban Consumer Price Index by 4.1% annually from 2015 to 2023. PGE's request for $45.3 million for Health and Wellness represents a 5.0% average annual increase since 2012, when PGE began expanding its high deductible plan offerings and increasing out-of-pocket costs for employees. Our request is an 8.0% annual increase from 2014 actuals. As Table 8 shows below, higher premiums are the main drivers for the increased cost in PGE's medical and dental benefits for 2015 and 2016.

Table 8
Non-bargaining Medical & Dental Premium (% change)

	2014	2015	2016*
Providence Personal	3.1%	6.6%	8.4%
Providence HDHP	8.5%	6.6%	8.4%
Providence Open	3.2%	6.6%	8.4%
Kaiser Medical	-6.0%	11.5%	6.5%
Kaiser HDHP	-5.6%	11.5%	6.5%
Metlife Dental	0.0%	6.0%	6.0%
Kaiser Dental	7.3%	7.3%	5.0%

* 2016 forecast provided by Mercer

While the 2015 increases in Table 8 represent actual increases for the year, Mercer consulting services provides PGE's forecasted rate increases for 2016. 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 premiums for the main bargaining unit are a negotiated benefit and managed by a Taft-Hartley Trust. We forecast that bargaining employee medical and dental plan premium costs will increase approximately 0.5% in 2015 and 9.0% in 2016. Our forecast is based on a semi-annual survey of local insurance companies' annual claims cost trends performed by Mercer (PGE's benefits consultant) and actual employee experience in 2013 and 2014.

Q. Have there been any legislative changes that affect health care costs?

A. Yes. In response to legislative changes, beginning in 2014, all temporary employees working at least 20 hours per week are eligible for medical benefits after 60 days of employment at PGE. Additionally, as health care reform continues to be rolled out over the next several years, PGE will continue to evaluate changes to its medical plan design in order to manage costs.

Q. What wellness expenses are included in the 2016 test year?

A. PGE forecasts approximately $0.4 million for wellness costs in 2016. Our wellness programs provide early detection of risk factors, intervention and management of health issues. These programs promote healthier lifestyles, which contribute to lower medical premiums, increased morale and 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.

Q. Has PGE changed its medical benefit design since the last rate case?

A. Yes. Previously, PGE targeted an overall premium ratio of 85% company and 15% employee for non-union medical, dental and vision premiums. PGE has discovered, though that because of this premium sharing structure, when employees left the traditional plan offerings for the high deductible health plans, the remaining share of premium costs were shifted to those in the traditional plans. This shifting resulted in moving PGE's employee medical benefits well below the market average, as seen in confidential PGE Exhibit 502. While this employee shift reduced PGE's overall health care premiums, it also resulted in abnormally high employee premiums for PGE's traditional plan offerings, affecting PGE's recruitment and retention strategies.

Q. Did PGE take any action to bring the medical benefit closer to market?

A. Yes. After reviewing our premium sharing structure and strategy, PGE shifted from an overall sharing structure of 85/15 to a targeted sharing structure. With the new structure, PGE covers 100% of the Providence Employee Only HDHP premium costs and shares the additional cost of all other plans with employees. As a result, the employee (and employer) benefit when shifting to the HDHP plan does not come at the detriment to those remaining in PGE's traditional health care plans, and PGE's medical benefits will become realigned with the market.

Q. You mentioned several times that PGE compares its benefit costs to the market. On which benchmark does PGE rely to measure and compare overall benefit costs?

A. PGE participates in the Towers Watson Energy Services BENVAL Study, a bi-annual 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 benefits plans.

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

A. According to the 2013 BENVAL survey, PGE's employer-paid non-bargaining medical costs are only 87% percent of the market average. Thus, we are paying less for medical costs than average. When looking at PGE's entire benefit program, the employer paid costs are at 98% of the market average. Together, this means that PGE is paying considerably less than peer companies for similar medical benefits. These two survey results from the study are provided as confidential PGE Exhibits 502 and 503.

Q. Who are the companies PGE is benchmarked against in the BENVAL study?

A. A three letter code is given to the companies in the study so that they can remain anonymous to one another. PGE's code is BLV. In general terms, PGE's peer group includes 16 regulated utilities with 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 from across the U.S., with a balanced representation across the western and eastern U.S.

Q. Please explain how PGE forecast its disability and life insurance benefit for 2016.

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 $0.6 million in 2016. This represents a $0.1 million increase from 2014 and is the result of a 10% rate increase in the renewal of the union short-term disability contract in the middle of 2016, coupled with union wage increases for 2015 and 2016. Costs for 2015 and 2016 reflect our claims history.

PGE forecasts long-term disability medical costs for union and non-union employees to be approximately $2.7 million in 2016. PGE uses a forecast by 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 the ending and beginning liabilities, plus the benefits actually paid by PGE in that year. PGE pays 85% of the health care benefits for non-union employees and 90% for union employees on long-term disability.

PGE forecasts retiree group life insurance costs to be approximately $1.0 million in 2016. 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 the Portland General Electric Company 401(k) Plan (401k) 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.[6]

PGE's 401k costs are based on employee contributions and PGE's match 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 2014 to 2016, costs associated with the 401k are expected to increase from $16.4 million to $18.0 million, or approximately 4.7% annually. We discuss pension obligations in Section V.

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

[6] 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.

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. For bargaining unit employees $1.00 per straight-time hour is contributed in the HRA account. Additional union HRA costs relate to the accumulation of notional hours for current employees and retirees receiving current HRA benefits. Total HRA costs for 2016 are expected to be approximately $1.3 million, representing a decrease of $1.5 million from 2014 costs.

Q. Are there any other changes to the management of the HRA?

A. Yes. PGE invested a portion of the HRA asset balance, and the expected return on that investment is reflected as a reduction to our 2016 budget. The opportunity to generate returns and the long time horizon will allow PGE to use trust earnings in lieu of company contributions in the future, resulting in lower benefit costs.

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, 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 ensuring 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 employees. We expect to spend approximately $0.9 million in 2016. Although small in dollars, these tools help balance employer provided benefits with the changing realities of our demographics and market position. PGE's miscellaneous benefits costs are primarily educational assistance and Service Awards.

- 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.
- 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.

Q. What is PGE's 2016 cost for benefits administration?

A. PGE forecasts 2016 benefits administration costs to be approximately $0.6 million. This represents an average annual decrease of 16.6% relative to 2014. Sharply rising health care costs, growing complexity and regulations have increased the costs of administration of benefits across the country. PGE has kept these costs low by reviewing and changing plan designs as necessary.

V. Pension

Q. Please describe PGE's defined benefit pension plan.

A. PGE sponsors a non-contributory, defined benefit pension plan, of which substantially all participants are current or former PGE employees. Eligible individuals vest after five years of service and accrue benefits based on a number of factors, including years of service and final average earnings.

Q. How is the benefit that employees receive determined?

A. Benefits are determined based on years of service to PGE and their base pay at the time of retirement. No overtime, incentives, or other pay is factored into this calculation.

Q. Has PGE taken any actions to limit its pension benefit obligation?

A. Yes. Effective February 1, 2009, new non-bargaining employees are ineligible for the pension plan. Closing the plan reduces PGE's and its customers' future liability and exposure to market fluctuations. PGE previously closed the plan to new bargaining unit employees effective January 1, 1999. In addition, PGE has not granted a cost of living adjustment for retirees since 1994, limiting the adjustment to only those receiving less than the minimum benefit.

Q. How has PGE's pension assets performed relative to the market?

A. PGE's pension plan assets have consistently outperformed similar sized pension plans for the last five years, being in the top decile of funds over the five years ending September 30, 2014. Additionally, from 2000 through 2013, PGE's pension plan performance outpaced the average pension returns of the nation's largest companies (companies listed in the 2014 *Fortune* 1000) by an average of 2.3% annually.

Q. Have PGE's customers benefitted from PGE's pension plan performance?

A. Yes. Better plan management and performance reduces PGE's FAS 87 expense, which directly benefits customers in two specific ways. First, during years when there is a rate case, our FAS 87 expense forecast is lower than it otherwise would be as a result of our effective plan management. Second, in the years between rate cases, if FAS 87 expense is lower than what is in rates, PGE is able to increase investments elsewhere, benefiting customers without an associated increase in rates.

Q. Please explain what components make up pension funding requirements.

A. The two different funding requirements related to pension cost are FAS 87 pension expense and Pension Protection Act (PPA) required cash contributions that grow PGE's prepaid pension asset. Section A, below, describes them in more detail and how they affect PGE.

A. Pension Funding Requirements

1. Pension Expense (FAS 87)

Q. Please describe the components of FAS 87 expense used to calculate pension expense.

A. There are five components used to calculate pension expense. These components are service cost, interest cost, expected return on assets, amortization of prior service costs/credits, and amortization of actuarial gains/losses.

- Service cost – The service cost is a calculation of the annual pension benefits accrued by active participants in the pension plan. Put simply, it is the amount current participants earn for the current year.
- Interest cost – Added to service cost is the interest cost for the year. Interest cost reflects the increase in the Pension Benefit Obligation (PBO) for the passage of time (i.e., time value of money) using the current discount rate.

- Expected return on assets – From these amounts, the estimated return on assets (calculated by multiplying the expected market return by the Market Related Value of Assets) is subtracted.
- Amortization of prior period service costs – Then the amortization of prior period service costs, which represents any changes to the plan, is added. For PGE, this small amount will be fully amortized by 2015.
- Amortization of actuarial gains/losses – Finally, the amortization of any actuarial gains or losses is included. This calculation determines the difference between what was previously forecasted to happen by the actuary and what actually happened, then spreads the gain or loss over the remaining service life of the plan.

Q. What assumption does PGE use for its expected long-term rate of return?

A. PGE uses an expected long-term rate of return of 7.5%, which is the same rate PGE used for UE 283.

Q. How is PGE's expected long-term rate of return determined?

A. PGE's expected long-term rate of return estimate is developed using information provided by Mercer Investment Consulting. Investment returns in coming years are not expected to match the returns observed in the prior two decades due to various macroeconomic factors.

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

A. PGE uses a discount rate of 4.02%, which is an average of the interest rates of a basket of long-term high quality AA-rated bonds. Because bond rates have dropped considerably over the last year, PGE's 4.02% discount rate is approximately 75 basis points below the rate used in our most recent general rate case (UE 283). This methodology is determined in accordance with Generally Accepted Accounting Principles.

Q. Why are these rates important?

A. The long-term rate of return and discount rate used, coupled with PGE's current pension assets, determines the level of PGE's pension costs for a given year.

Q. Who calculates the annual FAS 87 expense?

A. Consistent with standard accounting practices, PGE uses a professional third party actuary to determine our pension liabilities and expenses. The Financial Accounting Standards Board requires that pension expense be actuarially determined and that it reflect the service component of expense over the period during which employees render services. These third party actuaries have years of education and experience specific to pension accounting, making them uniquely suited to the task of forecasting and determining PGE's pension liabilities and expense.

Q. What is the purpose of FAS 87?

A. The intended purpose of FAS 87 is to smooth a company's pension expense over the life of its pension plan. This smoothing can be seen in the amortization components of pension expense.

Q. What is PGE's forecasted 2016 pension expense?

A. PGE's 2016 total pension expense is forecasted to be $25.3 million. However, PGE capitalizes a portion of its pension expense during capital projects, so the operations and maintenance expense portion is only $14.7 million. PGE's 2016 total pension expense is slightly lower compared to 2014. This decrease is due to a variety of factors moving certain forecasted pension expense components higher and some lower, including reduced interest cost, a slightly higher than expected return on assets, and a lowering of the discount rate used for pension expense calculations.

2. Prepaid Pension Asset & Cash Contributions (Pension Protection Act)

Q. Please summarize the requirements of the PPA.

A. Signed into law in 2006 and effective in 2008, the PPA creates and requires pension plan sponsors to meet minimum funding targets for private pension plans.

Q. Please explain PGE's prepaid pension asset.

A. PGE's prepaid pension asset is the aggregate of contributions in excess of FAS 87 expense. The two main determinants of the prepaid asset amount are direct cash contributions and the amount of FAS 87 expense incurred.

Q. How has the PPA affected the prepaid pension asset?

A. First, the PPA's amortization schedule for cash contributions is considerably shorter in length than the amortization schedule under FAS 87, which has significantly increased the difference between the build-up of the prepaid asset and its reduction through FAS 87 expense. Second, the PPA increased funding requirements, requiring large cash contributions to the plan in excess of FAS 87 expense. This federally required increase in cash contributions has contributed substantially to the size of the prepaid pension asset and can affect our overall financing ability. Absent regulatory treatment of these costs, PGE's opportunity to earn its allowed Return on Equity will be diminished.

Q. How much cash has PGE contributed to its prepaid pension asset pursuant to the PPA?

A. As a result of the new funding requirements, PGE contributed a total of $30 million in 2010 and $26 million in 2011.

Q. Does PGE expect to make a cash contribution in 2016?

A. No. At this time, PGE does not expect to contribute to its pension plan for 2016, though current actuarial projections estimate required cash contributions of approximately $80 million over the next ten years.

Q. What is the current 2015 year-end forecast for PGE's prepaid pension asset?

A. According to PGE's latest pension forecast, the prepaid pension asset is projected to be approximately $18 million at the end of 2015.

Q. What is the relationship between the prepaid pension asset and pension expense?

A. The prepaid pension asset is amortized through PGE's pension expense. That is, as PGE incurs FAS 87 pension expense, the prepaid pension asset is reduced by that amount, offset by cash contributions, if any. The prepaid pension asset effectively amounts to a difference in timing between the two: pension expense and cash contributions.

Q. If FAS 87 expense is reduced every time a cash contribution is made to the prepaid asset, how does the prepaid asset diminish?

A. While cash contributions reduce FAS 87 expense by increasing the asset base and therefore the expected "return on assets" component of FAS 87 expense, PGE continues to incur service cost, interest cost, amortization of prior service cost, and amortization of actuarial gain/loss. These remaining FAS 87 expense components continue to reduce the prepaid asset and as the plan gets closer to being fully funded, the cash contributions taper off, while FAS 87 expense continues to be incurred.

Q. Will this prepaid pension asset eventually reach a zero balance?

A. Yes. While cash contributions are only necessary to fund the plan, FAS 87 expense continues through the life of the plan, eventually reducing the prepaid pension asset balance to zero.

B. Pension Cost Recovery

Q. What is PGE requesting regarding pension cost recovery?

A. At this time, PGE is requesting the recovery of its 2016 net pension expense of approximately $14.7 million.

Q. Are any amounts related to the prepaid pension asset included in rate base?

A. No. PGE plans to continue monitoring UM 1633, Investigation Into Treatment Of Pension Costs In Utility Rates, and rate base will be updated depending on the outcome of that docket.

Q. What is the current status of UM 1633?

A. It is possible there could be a Commission order in UM 1633 during the latter part of 2015 but an exact date is unknown.

Q. Will PGE be updating its pension request based on the outcome of UM 1633?

A. To the extent there is an order received in UM 1633 that provides allowances for pension cost recovery that are different from what PGE is requesting in this case, PGE will revise its filing to reflect the change in policy.

Q. Are there any other open dockets regarding PGE's pension costs?

A. Yes. In 2012 (with reauthorizations filed in 2013 and 2014), PGE filed an application requesting deferred accounting treatment for pension expense amounts in excess of those allowed in UE 215, along with carrying costs associated with PGE's prepaid pension asset.

The initial application and subsequent reauthorizations are currently being held in abeyance, pending the outcome of UM 1633.

Q. If PGE were granted recovery of only pension expense, wouldn't PGE's pension plan be made whole over time?

A. No. PGE expects to make significant cash contributions to its pension plan to meet the requirements of the Pension Protection Act. PGE must finance these contributions, and pension expense does not provide recovery of PGE's financing costs. This has a detrimental impact on PGE's capital structure and earnings potential due to un-recovered financing costs. It can also adversely affect PGE's ability to attract necessary capital.

VI. Summary and Qualifications

Q. Please summarize your testimony.

A. PGE must provide a total compensation package sufficient to attract, retain, and 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. Barnett, please summarize your qualifications.

A. I received a Bachelor of Arts degree from Abilene Christian University, followed by a certification in Human Resources at Portland State University. I completed coursework toward an MBA at the University of Portland. As Vice President of Administration, I oversee Business Continuity and Security, and Human Resources areas.

After working in the California school system, I joined PGE in 1978 and have successfully bid and been selected for various positions at PGE. I became Vice President in 1998.

Q. Mr. Jaramillo, please summarize your qualifications.

A. I received a Bachelor of Arts degree in economics from Northwest Nazarene University and am completing coursework toward a Masters of Business Administration at the University of California, Los Angeles. 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.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
501	2012-2016 FTEs
502C	2013 BENVAL – Medical Active
503C	2013 BENVAL – Entire Benefit Program

DIVISION	CLASS	DEPT	REG/ TEMP	Officer	2012 FTE (PGE Share)	2013 FTE (PGE Share)	2014 FTE (PGE Share)	2015 Budget FTE (PGE Share)	2016 GRC FTE (PGE Share)	FTE Delta 2014 -2016	Annual % Delta 2014-2016
A&G - INFORMATION TECHNOLOGY Total					249.8	238.1	234.8	251.3	261.3	26.5	5.5%
ADMINISTRATIVE AND GENERAL Total					361.1	354.9	348.1	372.3	375.3	27.2	3.8%
CUSTOMER ACCOUNTS Total					406.9	398.9	397.2	409.2	402.9	5.6	0.7%
CUSTOMER SERVICE Total					85.7	84.1	87.7	100.4	99.0	11.3	6.2%
GENERATING - BEAVER Total					55.1	49.6	46.9	53.1	53.1	6.2	6.4%
GENERATING - BIGLOW Total					7.6	8.0	7.2	8.0	8.0	0.8	5.7%
GENERATING - BOARDMAN Total					72.9	71.5	93.3	109.1	105.5	12.2	6.3%
GENERATING - CARTY Total					-	-	-	7.4	20.7	20.7	#DIV/0!
GENERATING - COYOTE Total					16.8	16.2	16.2	17.9	18.5	2.3	6.7%
GENERATING - OTHER Total					280.0	285.6	294.2	315.6	321.4	27.2	4.5%
GENERATING - PORT WESTWARD Total					20.9	21.1	24.2	26.4	26.4	2.2	4.5%
GENERATING - TROJAN Total					11.7	11.2	11.8	12.2	12.2	0.4	1.5%
GENERATING - TUCANNON Total					-	-	2.1	5.0	5.0	2.9	55.7%
TRANSMISSION & DISTRIBUTION Total					927.9	913.9	919.7	978.9	976.7	57.0	3.1%
Grand Total					2,496.4	2,453.1	2,483.4	2,666.7	2,685.9	202.5	4.0%

Adjusted Totals by Division

IT	249.8	238.1	234.8	251.3	261.3	26.5	5.5%
Unfilled Position Adjustment				(7.3)	(12.6)	(12.6)	
MyTime Adjustment							
Adjusted IT Totals	249.8	238.1	234.8	244.1	248.8	14.0	2.9%
A&G	361.1	354.9	348.1	372.3	375.3	27.2	3.8%
Unfilled Position Adjustment				(10.8)	(12.2)	(12.2)	
MyTime Adjustment							
Escalation Adjustment							
Adjusted A&G Totals	361.1	354.9	348.1	361.5	363.1	15.0	2.1%
Adjusted A&G/IT Totals	610.8	593.1	582.9	605.6	611.8	28.9	2.5%
Customer Accounts	406.9	398.9	397.2	409.2	402.9	5.6	0.7%
Unfilled Position Adjustment				(11.5)	(11.0)	(11.0)	
MyTime Adjustment							
Incremental FTEs offset by Other Revenue							
Adjusted Customer Accounts Totals	406.9	398.9	397.2	397.8	391.9	(5.4)	-0.7%
Customer Service	85.7	84.1	87.7	100.4	99.0	11.3	6.2%
Incremental FTEs offset by Other Revenue				(4.0)	(4.0)	(4.0)	
Adjusted Customer Service Totals	85.7	84.1	87.7	96.4	95.0	7.3	4.1%
Adjusted Customer Accounting/Service Total	492.6	483.0	484.9	494.2	486.9	1.9	0.2%
Generation	465.1	463.2	495.8	554.6	570.7	74.9	7.3%
Unfilled Position Adjustment				(11.2)	(12.9)	(12.9)	
MyTime Adjustment							
Adjusted Generation Subtotal	465.1	463.2	495.8	543.4	557.7	62.0	6.1%
Remove Carty				(7.4)	(20.7)	(20.7)	
Adjusted Generation Total	465.1	463.2	495.8	536.0	537.0	41.2	4.1%
T&D	927.9	913.9	919.7	978.9	976.7	57.0	3.1%
Unfilled Position Adjustment				(15.7)	(26.2)	(26.2)	
MyTime Adjustment							
Incremental FTEs offset by Revenue				(12.0)	(12.0)	(12.0)	
Adjusted T&D Totals	927.9	913.9	919.7	951.2	938.5	18.8	1.0%
Unadjusted Total	2,496.4	2,453.1	2,483.4	2,666.7	2,685.9	202.5	4.0%
Unfilled Position Adjustment	-	-		(56.4)	(74.9)	(74.9)	
MyTime Adjustment							
Incremental FTEs not in Rates	-	-		(16.0)	(16.0)	(16.0)	
Reflect Carty	-	-	-	(7.4)	(20.7)	(20.7)	
Escalation Adjustment							
Adjusted Grand Total	2,496.4	2,453.1	2,483.4	2,586.9	2,574.3	90.9	1.8%
Match	-	-	-	-	-	(0.0)	

Exhibit 502C

Confidential

Exhibit 503C

Confidential

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Corporate Support
A&G - IT

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Jim Lobdell
Cam Henderson
Alex Tooman

February 12, 2015

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 Cam Henderson. I am the Vice President of Information Technology (IT) and Chief Information Officer at PGE. My qualifications appear in Section VI of this testimony.

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 $160.0 million in administrative and general (A&G) costs in 2016 and compare it to 2014 actuals, which were $156.2 million. We also provide context to show how these expenditures support PGE's ability to meet our customers' need for safe, reliable electric power at a reasonable cost, with service standards and practices that conform to norms in today's global business and technological environments.

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 2012 (actuals) through 2016 (test year forecast). Table 1 below summarizes the major A&G costs by functional area.

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

Major Functional Areas	**2014 Actuals**	**2016 Forecast**	**Delta***
Facilities/General Plant Maintenance	$5.5	$5.2	$(0.3)
Accounting/Finance/Tax	$9.7	$10.4	$0.8
HR/Employee Support	$9.2	$10.2	$1.0
Insurance, Injuries and Damages, etc.	$8.5	$11.3	$2.8
Legal	$4.6	$6.1	$1.5
Regulatory Affairs/Compliance	$2.6	$3.2	$0.7
Corporate Governance	$4.1	$4.5	$0.4
Business Support Services	$2.7	$2.9	$0.2
Environmental Programs	$2.7	$4.6	$1.9
Corporate R&D	$1.3	$3.1	$1.7
Contract Services/Purchasing	$1.2	$1.1	$(0.1)
Security and Business Continuity	$2.0	$2.7	$0.6
Corp Communications/Public Affairs	$1.9	$2.2	$0.3
Load Research	$0.2	$0.1	$(0.0)
Hydro Licensing	$0.1	$0.1	$0.0
Performance Management	$1.5	$1.9	$0.3
Governmental Affairs	$1.0	$1.2	$0.2
Total for Major Functional Areas*	**$58.8**	**$70.8**	**$12.1**
IT: Direct and Allocated	$10.2	$12.4	$2.2
Labor Cost Adjustment	0.0	$(3.0)	$(3.0)
Membership Costs	$2.4	$3.3	$1.0
Incentive Plans (net of capital allocations)	$21.2	$9.9	$(11.4)
Severance	$0.0	$0.2	$0.1
Regulatory Fees	$5.9	$8.3	$2.4
General Plant Maintenance	$2.3	$2.4	$0.0
Net PTO	$5.3	$5.9	$0.5
Benefits (net of capital allocations)	$52.3	$54.8	$2.5
Corporate Allocations	$(4.1)	$(6.8)	$(2.7)
Revolver Fees, Margin Net Int., Broker Fees	$1.8	$1.8	$(0.0)
Total Other A&G Costs*	**$97.4**	**$89.2**	**$(8.2)**
Total A&G*	**$156.2**	**$160.0**	**$3.8**

** May not sum due to rounding.*

Q. How would you characterize the forecasted increase in A&G costs from 2014 to 2016?

A. Most of the A&G cost increase from 2014 to 2016 is attributable to three primary drivers: benefits, environmental services, and insurance. Benefits, as discussed in PGE Exhibit 500,

[1] FERC defines administrative and general expenses as those that fall within FERC accounts 920 through 935.

are largely driven by health care costs. Environmental and Licensing Services encompasses the costs associated with regulatory reporting and compliance requirements (at federal, regional, state, and local levels) related to environmental issues and the increase in these costs reflect the same drivers discussed in PGE's last general rate case (UE 283). Insurance costs continue to be subject to the same trends that we identified in PGE's last two general rate cases (UE 262 and UE 283) and are described in more detail below. While we can and do actively manage costs associated with these drivers, they are primarily external to PGE and reflect larger market conditions and/or regulatory requirements beyond our control.

Secondary drivers for A&G's cost increase include:

- New projects for research and development;
- Increasing membership costs for PGE's participation in the Western Electricity Coordinating Council (WECC) as discussed in UE 283;
- Increasing demands to staffing and training;
- Increasing focus on company-wide safety and resiliency; and
- A higher level of IT costs.

Beyond these specific items, most other increases from 2014 to 2016 are a function of cost escalation due to inflation.

Q. Does your forecast include any cost reductions related to efficiencies?

A. As discussed in PGE Exhibit 500, PGE continues to look for and find efficiencies within its benefit programs. New for 2016, PGE was able to lower its Health Reimbursement Account forecast by approximately $200,000 because of efficiencies gained through a new investment strategy.

Q. How is your testimony organized?

A. In the next section, we describe the major cost drivers by A&G function. We then discuss PGE's Information Technology efforts on a corporate basis. Next, we provide detail regarding increases in other A&G costs. We then summarize our request in this filing. Our last section contains Mr. Henderson's qualifications.

II. Primary A&G Cost Increases

A. Benefits

Q. By how much do you forecast benefit costs to increase from 2014 to 2016?

A. The increase in net benefit costs from 2014 to 2016 is approximately $2.5 million and includes such items as health and dental plans, PGE's 401(k) and pension plans, and employee life and disability insurance.

Q. What accounts for this increase?

A. The primary drivers are increasing premiums for health care and dental insurance. PGE Exhibit 500 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 labor market for specialized and qualified applicants who can help deliver the high service-quality levels expected of us. Please note that the benefit amounts in Table 1 represent the "net" changes within A&G only, as compared to the gross costs applicable to corporate PGE. Net A&G refers to the amount remaining in A&G after labor loadings apply certain amounts of these costs to capital projects and "below-the-line" activities. PGE Exhibit 500 explains the gross corporate forecast for these costs.

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

A. As discussed in PGE Exhibit 500, PGE works to keep benefit costs down by sponsoring programs that encourage a healthy workforce, modifying benefits plan structures to track market practice, and negotiating favorable contract terms with vendors. Our goal is to maintain a fair and competitive benefits package that will help us attract and retain a quality workforce, while still controlling costs.

B. 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 Exhibit 603. In general, the insurance coverage maintained by PGE falls into two broad categories: property and casualty. We discuss these below and also address retained losses.

Q. What is PGE's forecast for insurance premiums for 2016?

A. As shown in Table 2 below, total property and casualty premiums are expected to be approximately $10.5 million, excluding property insurance for Carty Generating Station (Carty) and 50% of non-primary layers of Directors and Officers (D&O) insurance. The property insurance premiums are expected to increase due to an overall increase in PGE's total insured value coupled with an average annual 1.8% rate increase. Within the casualty program, PGE expects overall insurance premiums to increase in the range of 2.5% by 2016. The mild increase in premiums assumes a relatively soft to stable market for casualty coverage with the possible exception of workers compensation and cyber liability coverages. However, due to the removal of 50% of non-primary D&O layers of insurance, PGE's request for casualty insurance represents a 3.3% average annual decrease from 2014 actuals. Unforeseen severe casualty losses would produce upward pressure on rates beyond the current forecast.

Table 2
Insurance Premiums ($ millions)*

Type of Loss	2014 Actuals	2016 Test Year**	Average Annual % Increase
Property	$4.8	$5.6	7.9%
Casualty	$5.2	$4.9	(3.3)%
Total	**$10.0**	**$10.5**	**2.2%**

** Amounts exclude Carty policyholder/membership credits*
***2016 amounts are net of PGE's pre-filing adjustments*

Q. What is PGE's forecast of expenditures for retained losses from 2015 to 2016?

A. As shown below in Table 3, PGE's forecast of expenditures for retained losses increases by $0.7 million from 2014 to 2016. We discuss retained losses in more detail below in Section 5.

Table 3
Retained Losses ($ millions)

Type of Loss	2014 Actuals	2016 Test Year	Average Annual % Increase
Workers' Compensation	$1.5	$1.7	6.2%
Auto & General Liability	$1.1	$1.6	19.9%
Total	**$2.7**	**$3.4**	**12.2%**

1. PGE's Insurance Policies

Q. How does PGE determine the appropriate amount of coverage limits?

A. PGE maintains insurance to provide adequate financial protection from exposures to losses that could otherwise result in an adverse material effect on PGE's financial stability and potentially negatively impact customers as well as the company. For certain lines of coverage, limit requirements are determined by regulatory bodies. PGE also consults with insurance brokers and other subject-matter experts concerning appropriate limits. Benchmarking studies and utility peer group comparisons are reviewed to ensure that PGE's practices for purchasing insurance are consistent with utility industry practice.

Q. How does PGE structure its coverage limits for the various types of insurance purchased?

A. Within the utility industry, the ability to sufficiently insure a loss exposure often requires capacity that is beyond the underwriting ability of a single insurer. This is because most insurance companies manage their exposure to risk by limiting the amount of insurance capacity that they provide to any one company. To acquire adequate coverage limits, diversify exposure (to not excessively rely on any one carrier) and reduce risk, an insurance structure is assembled whereby the primary insurer provides specific coverage terms and capacity limits, but less than the total needed. Additional insurers provide supplemental capacity limits that are in addition to the primary layer while still following the form (basic terms and conditions) of the primary layer. The supplemental layer attaches to the underlying layer to form a single cohesive insurance program. In structuring coverage this way, PGE is able to secure the adequate level of insurance capacity needed to protect against the adverse effects of severe losses with competitive pricing, as well as to diversify exposure to any one carrier. This practice is common in the insurance industry and reduces overall risk.

Q. How does PGE forecast its insurance premium costs?

A. We base the estimates on the most recent data for PGE's insurance program, adjusted to account for:

- Amount and type of property or potential losses;
- Trends in insurance pricing and capacity provided by insurers, insurance brokers, consultants, and industry analysts;

- Changes expected in its various insurance programs in the coming years, such as increases or decreases in limits purchased, or property being added or retired, inflationary indexing of existing property base; and
- PGE-specific considerations, such as the frequency and severity of claims, which might have an impact on future premium expenses.

2. Current Trends

Q. Please describe current conditions of the global insurance market.

A. The outlook for the global property & casualty insurance market is generally stable. Broadly speaking, insurers have benefited from the rate increases of recent years and we are beginning to see a tapering off with overall rate growth expected at low single digits in North America. Stronger economic growth, favorable loss experience and a gradual rise in interest rates are all factors that tend to keep insurance pricing down. However, factors such as materially weaker economic growth, and increases in catastrophic losses, which the market must absorb, put upward pressure on insurance rates.

Q. Please discuss current property insurance market conditions.

A. Lower than expected Atlantic hurricane activity and other natural catastrophes, coupled with abundant capacity helped to keep property insurance pricing stable through the end of 2014. Barring any significant natural catastrophe losses, we expect to see pricing stability continue into early 2015.

Q. What are the current market conditions for general liability insurance?

A. Utility sector general liability insurance rates in 2014 continued to see double digit increases as insurers continued to rebuild their policyholder surplus. We expect pricing to stabilize in

2015 as utility underwriters begin to see some profitability return to their books resulting in a mild increase of roughly 2%.

Q. What are the current conditions in the D&O liability insurance market?

A. The Directors' and Officers' (D&O) insurance market remains stable for the majority of industries due in part to relatively low frequency of securities class-action events, high rate of dismissals, and an abundance of capacity. Within the utility sector, merger-related filings continue to be a leading cause of D&O claims and a key issue for D&O underwriters. We expect to see the soft market and stable pricing continue into 2015.

Q. Are there other significant trends related to insurance coverage?

A. Yes. Data breaches have continued to increase across the U.S. Some of the higher profile breaches occurred at Home Depot, Target, Sony, the U.S. Postal Service, Staples, and JP Morgan. Despite the 783 reported data breaches and 85.6 million records exposed in the U.S. in 2014[2], pricing has remained relatively stable with the exception of retail and healthcare industry segments where the majority of data breaches have occurred. Since 2009, PGE has maintained cyber liability coverage to help mitigate the financial consequences of a cyber-attack or data breach.

3. Property Insurance

Q. You noted above that the property insurance market is experiencing price stability. Why are PGE's property insurance premiums increasing by an annual average of 7.9%?

A. On a combined program basis, PGE expects property insurance rates to increase between 3.0% and 4.0%. However, overall premiums are expected to increase in the range of 21%

[2] http://www.idtheftcenter.org/images/breach/DataBreachReports_2014.pdf

over the two-year period of 2014 to 2016, driven mainly by increases in insured values due to the addition of Tucannon River Wind Farm, Port Westward 2, and Carty. Unforeseen severe property losses would produce upward pressure on rates beyond the current forecast.

Q. Will the addition of Carty cause PGE's property insurance premiums to increase in 2016?

A. Yes. We expect Carty to increase PGE's 2016 property premium by approximately $0.2 million in addition to the 2016 property premium shown in Table 2 above. PGE Exhibit 300 discusses Carty in more detail.

4. Casualty

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

A. Table 4 below lists the eight components of PGE's casualty insurance program.

Table 4
Casualty Program Components

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 protects customers and shareholders from the consequences of financial distress of potential claims;
- The limits purchased are consistent with standard practice of the utility industry 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 rates 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.

5. Retained Losses

Q. What are 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 method does PGE use to forecast workers' compensation, auto liability, and general liability losses?

A. Annually, PGE engages the services of an independent actuarial firm to provide loss projections related to auto and general liability losses. The independent actuarial firm assembled and analyzed 18 years of historical auto and general liability losses to project the losses for 2016.

Workers' compensation liability loss projections are based upon analysis of past claims and current available information. The 6.2% increase in workers' compensation projected loss is a function of actuarial review and historical losses.

The annual budgeted claim expenditures for workers' compensation losses do not include the costs related to time loss or supplemental work loss payments (benefits for wages lost due to work related injuries). Such costs are already budgeted within the wages and salaries (W&S). Time loss and supplemental work loss payments are equal to or less than the regular W&S received by injured employees who cannot return to work.

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 3 above, PGE's retained losses in 2016 for auto liability and general liability are expected to increase by an annual average of 19.9% from 2014. The actuarial projection for auto and general liability retained losses is directly correlated to PGE's actual loss experience over time. In recent years, PGE has seen an increase in loss severity that adversely impacts the actuarial projection for 2016.

C. Environmental and Licensing Services

Q. By how much do you expect environmental and licensing service costs to increase from 2014 to 2016?

A. We forecast that Environmental and Licensing Service (ELS) costs, as charged to A&G, will increase from approximately $2.7 million in 2014 to $4.6 million in 2016. This increase is primarily related to the remediation of portions of the Downtown Reach area of the

Willamette River and is based on the stipulated increase of $3 million spread over 2015 and 2016 as approved by Commission Order No. 14-422 (Docket No. UE 283).

Q. Please describe the environmental activities associated with the Downtown Reach.

A. The Downtown Reach area of the Willamette runs from River Mile 11.8 to 16.0. In 2015, PGE expects to be involved in remediation activities in the Downtown Reach at River Miles 13.1 and 13.5 in compliance with Oregon Department of Environmental Quality (ODEQ) and U.S. Environmental Protection Agency (EPA) regulation.

In February 2014, PGE submitted the draft Feasibility Study (FS) to ODEQ. In May of 2014, PGE prepared and submitted a follow-up memorandum regarding the standards and techniques used in preparing the FS. We expect the ODEQ to complete their evaluation by the end of the first quarter of 2015. The remedial action will begin in 2015 with the in-water work period.[3]

Q. What are the expected costs of the remediation projects in the Downtown Reach?

A. PGE estimates the remediation cost at River Miles 13.1 and 13.5 to be approximately $1.5 million annually for 2015 and 2016.

Q. Does PGE expect reimbursement of those expenses?

A. PGE continues to receive 45% of undisputed costs associated with the defense and investigation from two insurers regarding the Portland Harbor and Downtown Reach areas, but we have not reached agreement with insurers regarding expected remediation for River Miles 13.1 and 13.5 in the Downtown Reach area. As part of PGE's continued involvement in the Portland Harbor Superfund site and Downtown Reach, and in an attempt to recover legal, investigation and clean-up costs, PGE notified all identified domestic and London

[3] The in-water work period is the time available for working in the water due to fish passage being at a low point in the river.

insurers that remain solvent of the environmental claim. PGE continues to pursue similar defense cost-sharing agreements with other insurers.

Q. Will PGE bid the remediation work to outside experts through a request for proposals?

A. Yes. PGE will bid the remediation project to outside contractors and may bid the verification and report writing as well. These outside experts will administer and implement the remediation effort in phases, which are as follows:

- Permitting and Design Labor: project scoping/planning and review, communications with client and ODEQ, finalization of the permitting requirements, plans and permit application/design revising, if needed, and general project administration.
- Contractor Procurement: project management, bid review and contract implementation, review health and safety for subcontractors, review of bids, training requirements and qualifications for contractors, review of submittals, scheduling, design and approach, plus work order preparations.
- Oversight and Remedy Implementation: project management, review of compliance documentation, project coordination, sample collection confirmation, water quality monitoring, waste management, oversight during construction, field support as needed, project invoicing and correspondence oversight.
- Draft Remedial Action Report (RAP): Review of draft RAP document, compliance document preparation, post remedy risk assessment evaluation, reporting, logging sampling data, sample sheets, general work flow schedule, reporting and preparation, plus project administration and document formatting.

Q. What are the remedial activities expected to involve?

A. The final FS will address the installation of an isolation cap for River Mile areas 13.1 and 13.5, and will also:

- Address the designated objectives for sediment remediation.
- Reduce mobility of the "chemicals of concern" in the underlying sediment.
- Protect human health and ecological receptors through implementing appropriate engineering and institutional controls (e.g., engineering and installing the isolation cap and limiting access to the site by placing an easement on the bottom of the river).
- Implement effective treatment of surface and subsurface areas of contamination.
- Substantially reduce the "site-specific surface weighted average concentration" as well as reliably prevent the risk to future human and environmental health.

Q. Does this comprise all of the environmental costs charged to PGE?

A. No. Environmental and Licensing Services consists of two principal activities:

- Operations & Maintenance (O&M) costs associated with remediation, investigation and reporting are incurred in A&G, primarily FERC accounts 920 (Administrative and General Salaries) and 923 (Outside Services Employed).
- Work related to generation resources (e.g., FERC license and Site Certificate compliance at generating facilities, as well as all other local, state and federal regulatory compliance) are incurred as part of Production O&M, primarily FERC account 537, Hydraulic Expense, as discussed in PGE Exhibit 700.

Table 5 below, summarizes PGE's total ELS costs for 2014 and 2016.

Table 5
Environmental and Licensing Services by Operating Area
($ millions)

	2014 Actuals	2016 Test Year*	Delta
A&G	$2.7	$4.6	$1.9
Production O&M	$2.9	$5.2	$2.3
Total ELS**	**$5.6**	**$9.8**	**$4.2**

**Amounts exclude Carty*
*** Totals may not sum due to rounding*

D. Research and Development

Q. What are PGE's forecasted 2016 costs for PGE's corporate Research and Development (R&D) activities?

A. For 2016, we forecast approximately $3.1 million in R&D expenses, of which $2.8 million is for specific R&D projects and the remainder is for administrative costs. This reflects an increase of approximately $1.3 million compared to the amount recently approved in UE 283, and approximately $1.7 million over 2014 actuals. The increased spending represents numerous selected projects that are necessary to address the significant changes and new technologies facing PGE and the electric industry. These 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 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 6 below provides a listing of the 2016 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 6
Topical Summary of 2016 R&D Applications ($ millions)

	Category	Approx. Cost	Number of Projects
SG	Smart Grid	0.8	17
SR	System Reliability	0.7	19
RP	Renewable Power	0.5	8
OE	Operational Efficiency	0.4	13
ES	Energy Storage	0.2	4
SY	System Resiliency	0.1	2
	Total*	**$2.8**	**63**

**Total may not sum due to rounding*

Q. What is PGE doing to pursue R&D in a cost effective manner?

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 can profoundly alter the present grid. Many of the R&D projects are leveraged financially by working with other utilities as well as universities to co-sponsor shared R&D. 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 larger federal or other institutional grants, and would 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 and sequestration through torrefied biomass fuel use to displace coal (see PGE Exhibit 604, Pages 5-7 for examples). Two projects utilizing financial leveraging are as follows:

1. The active wave energy research project at the Northwest National Marine Renewable Energy Center (NNMREC), under the guidance of Oregon State University (see PGE Exhibit 604, Project 1); and

2. The 25 research projects PGE conducted from 2012 through 2014 with Portland State University (PSU).

The US Department of Energy is providing the bulk of NNMREC funding ($7.25 million over a multiple year period). Four of the 25 PSU projects required no contribution from PGE as they were performed as part of PSU's Capstone Program. Capstone projects are research opportunities that companies make available to universities for students, under the direction of a professor, to fulfill a needed academic requirement and provide valuable research.

Q. How have PGE's customers benefited from R&D in the past?

A. The best recent example of customer benefit involves the demonstration involving the use of the substantial battery inverter system at PGE's Salem Smart Power Center, with the output signal from a nearby 114 kW solar photovoltaic system. PGE and Portland State University collaborated on this demonstration over 2013 and 2014. It successfully allowed a feeder line emanating from PGE's Oxford Station in Salem to peak-shave and firm a medium-voltage feeder line. We understand this demonstration to be the first successful one in the electric utility industry.

Q. What is your plan for 2016 SG projects?

A. PGE has proposed 17 SG projects, including the following.

- PGE will join the EPRI research target and participate in a larger collaborative to demonstrate use of demand response (DR) ready appliances.
- Evolve model criteria for the establishment of micro grid capability with a full islanding feature.

These and other projects explore improving grid response to the increase in distributed sources of renewable power and DR resources that are variable or cannot be predicted with precision, let alone necessarily be dispatched to meet demand. Addressing the use of these power resources effectively and safely will be critical in support of their expected high level of grid adoption in the foreseeable future.

- PGE will focus on software and communications development for sensing, controlling and monitoring the grid as grid operations evolve in the future. An example is full implementation of four advanced smart switches in Salem. This will offer increased situational awareness to the grid operator and can offer increased reliability by rapidly segmenting only the faulted portion of the circuit. This need is fundamental because it is the communication and control software that must be created in order to utilize, synthesize, interpret, and react to the massive amounts of SG data.
- PGE will implement SG projects that build on its Salem Smart Power Center (SSPC) where PGE installed five MW of batteries that can store 1.25 MWh of energy. Additional projects include assessing the batteries' use as part of PGE's successful and unique dispatchable standby generation (DSG) program and in a role that can support dynamic conservation voltage reduction (CVR). The latter is a version of static conservation voltage reduction that can be much more effective in grid-scale energy efficiency but does rely on the presence of an energy storage device, which is now available at the SSPC. In total, PGE has identified 12 potential use cases (see PGE Exhibit 604, Projects 9, 15, 16 as examples) that build on the SSPC assets and their implementation in smart grid roles.

PGE Exhibit 604 provides a detailed listing of all the 2016 SG projects. PGE will continue to address projects further in its annual Smart Grid Reports (RE 141 and through Docket Nos. UM 1460 and UM 1657). Moreover, PGE continues to participate in significant smart grid workshops with stakeholders and Commission staff covering energy storage and smart grid metrics development.

Q. Please summarize other 2016 R&D efforts and the reasons behind these efforts.

A. There has been a notable departure from the central power generation model using fossil and nuclear fuels to a more distributed power generation model utilizing non-dispatchable renewable power and smart inverters to deliver power to the grid. Rapid cost-competitiveness of solar photovoltaic power generation, continued subsidies for renewable power and national and state level policies to drive down greenhouse gas emissions in response to global climate change are driving this different power generation paradigm. In fact, as more distributed power generation comes on-line, there are policy mandates (e.g., California's 2013 requirement for 1,325 MW of grid-scale energy storage) to deploy energy storage to provide grid and smaller scale energy capacity resources. Additional research will be needed to accommodate this new distributed power future for the benefit of PGE's customers. Moreover, for the purposes of grid operation, voltage and frequency stability, it will also be necessary to track and control electrical resources (e.g., stationary and mobile batteries, solar PV) on both sides of the customer meter.

In addition, PGE continues R&D in the growing, charring, and combustion of biomass as a substitute for coal at the Boardman Plant. Giant cane (*Arundo donax*) and other potential biomass feed stocks are considered renewable fuels in Oregon, which if proven cost-effective, could be used to allow for the continuation of Boardman as a base-load, renewable power resource. This would significantly help PGE meet Oregon's renewable energy standard (RES), while reducing PGE's overall carbon footprint. It is also sustainable as Boardman would be a substantial sunk cost that can be re-used for a similar but improved purpose.

Q. Are there additional benefits in implementing the 2016 proposed research projects?

A. Yes. As stated in PGE's 2013 Integrated Resource Plan (IRP), PGE must continue to add renewable resources to its system to meet Oregon's Renewable Energy Standard. This is being accomplished by the recent completion of PGE's new Tucannon River Wind Farm, near Dayton, WA, which joins PGE's Biglow Canyon wind facility in Sherman County, Oregon. R&D projects in 2016 are designed to further optimize and support these substantial renewable power installations. By doing so, we will be proactive, rather than reactive, to evolving technologies and regulation (e.g., using charred-biomass renewable fuel and distributed solar generation). By supporting demonstration projects and activities with other research groups (e.g., EPRI, national laboratories, and universities), PGE will avoid missing opportunities to participate and direct how resources are developed for maximum customer benefit. This includes fine-tuning the operation of these renewable resources to extract the maximum power output, accommodating and improving their grid integration.

PGE customers continue to derive value from projects of increasing importance such as demand response, additional smart grid applications and carbon offsets/reductions. PGE will use R&D funds to improve reliability of its generation and distribution systems and participate in opportunities to review and apply system improvements through demonstration projects. An example of a 2016 demonstration involves the installation of remote temperature sensors in switchgear cabinets at PGE's Beaver Power Plant, providing PGE with routine measurement of temperature increases that could signify a developing fault before the fault is allowed to happen (see PGE Exhibit 604, Reliability Project 50). Remote assessment capability also reduces the potential for arc flash inasmuch as maintenance staff would not have to open the switchgear cabinets for inspection. PGE's participation in demonstration projects, trade programs, and specific-issue research continues to provide value to PGE's staff and customers over the long run from the perspectives of increased safety, productivity and grid reliability.

Finally, in the development of electric transportation, it is very possible that internal combustion technology will eventually be replaced with electric drive systems in vehicles. This notion has gained traction in recent years with current construction of lithium ion battery manufacturing capability on the order of gigawatt-hours. In anticipation of that potential, PGE will focus R&D on promising infrastructure and systems that are becoming available to facilitate this technology.

This includes research into joint or transitional uses of electric transportation infrastructure with aspects of PGE's grid. For example, a proposed project to assess the potential for deploying lightly used electric vehicle (EV) lithium ion batteries for stationary power use (see PGE Exhibit 604, Energy Storage, Project 62). This is possible because routine EV use degrades the battery sufficiently such that it loses its appeal in a mobile application whereas there is still plenty of life in it for stationary use. One stationary power application for these batteries would be to support adaptive conservation voltage reduction on selected distribution circuits; another application would be to use the battery capacity to help integrate distributed solar photovoltaic generated power – again, on selected distribution circuits (see PGE Exhibit 604, Smart Grid, Project 19).

Q. Please summarize why PGE is requesting an increase in R&D funding.

A. PGE is requesting additional funding for R&D because technologies are rapidly changing and opportunities for customer savings, innovation, and reliability improvements are increasing. The funding increase reflects projects that strengthen the present grid, while at the same time prepare for the grid of the future.

III. Information Technology

A. Overview

Q. What activities or functions are you including as IT?

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

Q. By how much do you expect IT O&M costs[4] to increase?

A. From 2014 to 2016, we forecast total incurred IT costs to increase from $47.1 million to $54.0 million.[5] Because these costs relate to all areas of PGE's operations, they are charged or allocated 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.

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

A. As seen in Table 7 below, PGE's IT costs consist of three categories: directly charged (or assigned), allocated, and labor loadings/corporate governance allocation. Directly charged costs relate to systems that apply to specific operating areas, such as production, transmission, or distribution. These costs are charged directly to specific O&M accounts related to those operations. Other IT work in the areas of voice, data, network, communications, business recovery, the data center, and office systems are not directly

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[4] Unless specifically indicated as capital costs, all costs in this testimony refer to O&M costs.
[5] The IT amounts listed in Table 1 relate only to the costs charged and allocated to A&G. The total IT amounts represent the costs charged and allocated to all operating areas.

related to one specific operating area. Instead, these costs apply broadly to all PGE activities and departments and are first charged to a balance sheet account and then allocated to the expense accounts of the various functional areas. 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 OPUC Staff as an attachment to our Affiliated Interest Report. A summary of IT charges to each operating area by direct charge and allocation is provided as PGE Exhibit 605.

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.

The corporate governance allocation is similar to loadings in that the costs are first charged to A&G and then applied to O&M accounts, based on specific rates per allocated IT labor. As with loadings, they are not specifically IT costs, rather they are A&G costs that follow allocated IT labor costs.

Table 7
Total IT Costs ($ millions)

Category	2014 Actuals	2016 Forecast	Variance 2016–2014
Direct Charges to Operating Areas	$10.7	$11.0	$0.3
Allocated Charges to Operating Areas	$36.4	$44.6	$8.2
Labor Adjustment	$0.0	$(1.6)	$(1.6)
Subtotal IT Incurred	**$47.1**	**$54.0**	**$6.9**
Labor Loadings Charged to Operating Areas	$12.3	$14.8	$2.4
Corp Governance Allocation to Operating Areas	$0.6	$0.7	$0.1
Subtotal IT Loaded	**$60.0**	**$69.4**	**$9.4**
2014 IT Deferral Mechanism	$(6.9)	$1.7	$8.7
Total IT*	**$53.1**	**$71.2**	**$18.1**

** May not sum due to rounding.*

Q. Why do loadings increase by $2.4 million?

A. The loadings are projected to increase because the labor on which they are based is increasing due to escalation and higher full time equivalent employees (FTEs – discussed below). PGE Exhibit 500 provides details regarding the underlying payroll-related costs.

Q. What does the IT Deferral Mechanism represent?

A. As part of the UE 262 settlement process, parties stipulated that for 2014, O&M costs associated with developing IT systems should be capitalized and subject to a five-year amortization (although all parties did not necessarily agree with the position.) 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 to be included in 2014 rate base; and
- Amortization expense of approximately $1.7 million representing one-fifth of the capitalized amount.

Q. How does the IT Deferral Mechanism affect the 2016 forecast relative to 2014 actuals?

A. It gives the appearance that IT costs increase by approximately $8.7 million. This is unavoidable because the mechanism reduced costs in 2014 but there is no similar mechanism for 2016 costs. Both the 2016 forecast and 2014 actuals include the one-fifth amortization of the regulatory asset. Ultimately, between loadings, allocations, and in particular the IT deferral mechanism, most of the cost increase listed in Table 7 reflects items that do not relate to specific IT O&M expenditures.

B. IT O&M Costs

Q. What are the primary drivers of the increase from 2014 to 2016 related to direct and allocated IT charges shown in Table 7, above?

A. The increase is primarily attributable to the following drivers:

- Costs associated with PGE's 2020 Vision program, which has major projects being completed in late 2014 and the first half of 2015;
- Higher software and hardware licensing and maintenance costs based on the completion or continuation of other projects in 2015 and 2016; and
- Labor and non-labor cost escalation.

1. 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 the program's primary objective is to replace obsolete technologies. Additional objectives include:

- Support a safe and reliable power delivery system;
- Gain operational efficiencies through business process improvement;
- Meet customer and PGE needs for accurate and "real-time" information;
- Reduce the number of applications and reduce the number of vendor relationships;
- Integrate data across applications (reduce redundancy and inconsistencies); and
- Maximize the potential of Smart Grid technology.

Q. What 2020 Vision projects has PGE successfully implemented to date and what were their capital costs?

A. From 2010 through 2014, PGE completed the following 2020 Vision projects:

- <u>Work Management System (WMS) Upgrade</u>, $0.2 million – To upgrade Distribution's legacy work management system to ensure continued vendor support and compatibility with other PGE systems until that system is removed from service in 2015.
- <u>Finance and Supply Chain Replacement Project (FSRP)</u>, $26.5 million – To replace PGE's 26-year old financial system, which was no longer supported by the vendor, along with associated applications (e.g., spreadsheets, custom developed programs, etc.). We also reduced the number of financial systems by eight and integrated the new system with other applications.

- Infrastructure (hardware) and Program Office, $7.7 million – Represents hardware costs and project management for 2020 Vision.
- Maximo, Mobile and Scheduling Wave 1, $36.1 million – Modernized and consolidated PGE's mobile and scheduling tools into a single application and standardized hardware. This system enables consistent and comprehensive tracking of work and assets, and is integrated with other work systems to be used in scheduling, dispatching, and updating field work. Wave 1 is used primarily by generation and substation operations as well as individual field personnel (as opposed to crews) within transmission and distribution (T&D).
- Maximo for IT, $1.7 million – Replaced PGE's previous IT work management system, which was no longer compliant with our security policies. Maximo for IT supports our new, metric-based IT Service Management processes and provides a common asset database across PGE.
- "myTime" Time Collection System, $8.1 million – A web-based solution that captures time and labor data and automates complex rules, regulations, and union contract provisions regarding pay. In addition, myTime automates "leaves management" processes and accounts for contingent workers.
- Maximo, Mobile and Scheduling Wave 2 (Wave 2), $30.8 million – To add functionality for T&D operations plus additional users (e.g., line crews and joint-use employees). PGE Exhibit 800 provides additional detail on this and the projects expected to close in 2015.

Q. What 2020 Vision projects have you forecasted to close in 2015 and what are their estimated capital costs?

A. We expect to close the following projects:

- Geographic Information System (GIS) and Graphic Work Design (GWD), $21.0 million estimated – The new GIS system will improve the accuracy of PGE's asset location data, provide field employees with interactive access to asset information, and enable PGE to share critical information with emergency response and public officials. GWD will provide mobile field design capabilities that will reduce manual/paper-based work processes and reduce design time for non-complex, customer-requested jobs.
- Outage Management System, $21.8 million estimated – To replace PGE's in-house developed application with a modern, vendor-supported application that will improve response time, crew efficiency, and outage information.

Q. Do you expect any 2020 Vision projects to close in 2016?

A. No. The last remaining 2020 Vision project is the Customer Engagement Transformation (CET) program and is expected to close in 2017. PGE continues to develop the CET program to replace our current Customer Information System and Meter Data Management System and is discussed in PGE Exhibit 900.

Q. Do the 2020 Vision projects result in increasing costs from 2014 to 2016 and what do those costs entail?

A. Yes. These projects will entail 'Day 2' support and increasing hardware and software maintenance agreement costs.

Q. What are the Day 2 support costs?

A. These costs represent the on-going labor costs associated with supporting and maintaining our new software applications. After an application is developed and becomes operational, on-going technical support is necessary to maintain the application. In addition, with these new systems, IT will support a user base that will more than double, from approximately 700 users to 1,500 users.

Q. You mention above that 2020 Vision is intended to replace numerous applications with fewer enterprise systems. If you have fewer applications to maintain and support, why is more support needed?

A. Overall, PGE has reduced the number of applications supported, however, due to greater complexity of the new enterprise applications, additional on-going support is necessary. The increased complexity and need for additional support reflects the new systems having:

- More or new functions/capabilities – For example, the GWD system is an application that will provide new functions/capabilities that will 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, compared to approximately 20 interfaces for the legacy Maximo system. These interfaces automate or keep clients from manually keying information into multiple systems and provide for consistent/common data management. Interfaces add complexity because interfaces could have errors, or transactions might fail, and this becomes another area requiring IT support.
- New security policies and standards – The more complex systems, especially those with greater scope and capability, may introduce further sensitive or confidential data. If so, the solution will have additional security requirements that must be maintained on an ongoing basis.

Q. Are these Day 2 support costs labor based?

A. Yes. IT FTEs are projected to increase by 14 from 2014 to 2016. Of these, seven FTEs (approximately $0.8 million) are needed to meet IT's need for additional Day 2 Support to maintain new applications and support an increased user base. The remaining FTE increase is discussed in Part B.2., below.

Q. Why are software and hardware maintenance agreements necessary?

A. PGE must maintain these technologies to:

1) Keep them operational by having access to fixes and patches provided by the vendor;
2) Keep our software compliant by retaining appropriate licenses. Some vendors require maintenance as a condition of the original purchase for usage of the software; and
3) Receive regular upgrades to correct programming errors and provide continued technical maturity.

Q. In previous rate cases, you stated that the 2020 Vision program was intended to replace numerous applications with fewer enterprise systems. If so, 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 more effective enterprise applications, or 2) expanded use of existing applications (which is especially pronounced as we replace homegrown software, which requires no maintenance charge 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. By how much do software and hardware maintenance agreement costs increase based on the 2020 Vision projects?

A. From 2014 to 2016, these costs will increase by approximately $1.6 million.

2. Other IT O&M

Q. What are the remaining sources of IT cost increases from 2014 to 2016?

A. One source is additional software and hardware maintenance agreements on new, expanded, and/or current systems (not including the 2020 Vision projects discussed above). O&M costs for maintenance agreements on hardware and software tend to increase annually due to the following reasons:

- Cost escalation;
- Implementing new applications to meet new or changing requirements; and
- Replacing obsolete systems with more effective systems that deliver greater functionality and 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, and appropriate to, the purchasing of new technologies or expanding the usage of existing technologies.

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

A. Examples of new or expanded technologies include: the continued expansion of PGE's voice over internet protocol phone technology, the Customer Engagement Transformation program (see PGE Exhibit 900), the energy management system, risk management software consolidation, Business Intelligence Reporting Tool (BI), and PI system. Not including the 2020 Vision costs, software and hardware maintenance agreement costs increase by approximately $2.5 million including escalation and new/expanded systems.

Q. What are other sources of cost increases from 2014 to 2016?

A. As noted above IT FTE's increase by 14 with seven needed for 2020 Vision Day 2 support. The remaining seven FTEs are needed as follows:

- Three FTEs for Day 2 support of the BI tool; and
- Four FTEs represent requirements for cyber security specialists and FERC's critical infrastructure protection version 5 (CIPv5) implementation. PGE originally planned to hire the CIPv5 FTEs in 2014, based on an expected July 2015 effective date of the new standards. FERC's delay in finalizing and publishing the reliability standards, however, resulted in the effective date being moved to April 2016. Because of FERC's delay, PGE withheld hiring the FTEs until the work could effectively begin.

IV. Other A&G Cost Increases

A. Memberships

Q. Please explain the increase in the membership costs from 2014 to 2016.

A. PGE's membership costs are forecasted to increase from approximately $2.4 million to $3.3 million from 2014 to 2016. Membership costs for PGE's mandatory participation in WECC, projected at $2.2 million in 2016, account for the majority of this increase.

Q. What accounts for the increase in the WECC membership?

A. As discussed in PGE Exhibit 700 in UE 283, on January 1, 2014, WECC completed its separation into two entities:

- Peak Reliability is responsible for: 1) reliability coordination; 2) interchange authority; 3) reliability coordinator training; 4) the western interconnection synchophasor program; and 5) system operating limits methodology for the operations horizon.
- WECC is responsible for: 1) developing electric reliability standards; 2) providing monitoring and enforcement activities for compliance with reliability standards; 3) providing event analysis and lessons-learned from system events; 4) acting as a centralized repository of information relating to the planning and operation of the Bulk Electric System; 5) coordinating system planning and modeling; 6) providing information related to industry best practices; 7) facilitating resolution of market seams and coordination issues; 8) securing the sharing of critical reliability data; and 9) providing a robust stakeholder forum.

Because these entities will have separate administration, management, and Boards of Directors their costs have begun to increase significantly. To address this and other changes within WECC, PGE has increased its forecasted budgeted membership fees for WECC by approximately $980,000 above fees paid in 2014.

B. Business Continuity and Emergency Management

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

A. PGE's costs for BCEM are forecasted to increase from approximately $766,000 to $1,250,000 from 2014 to 2016. Similar to the 2015-projected expense, as discussed in PGE Exhibit 700 in UE 283, we base this increase on the development of a BCEM roadmap that establishes the activities PGE needs to perform through 2018 to achieve a target level of resilience among PGE's primary departments/systems.

Q. What is the purpose of the BCEM department?

A. BCEM was established 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. What do you mean by "target level of resilience"?

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 establish a department's resilience, the BCEM roadmap establishes a timeline for each primary department/system to undergo the following cycle:

- Establish plans to restore operations;
- Train employees on restoration procedure;
- Perform exercises to test employees; and
- Evaluate performance.

The cycle will be an annual mechanism to continue to strengthen PGE's capacities and capabilities for emergency response.

Q. How is this different from your earlier efforts at BCEM?

A. It is different only in degree and scope. Until 2012, BCEM operated with only three or fewer FTEs (with approximately two of these FTEs for support and administration). This has limited the number of areas within PGE that BCEM has been able to support with its full range of duties. With the growing recognition of the potential for detrimental events and the increasing emphasis on protecting critical energy infrastructure, PGE determined that its BCEM efforts needed to be accelerated. To this end, we have established the roadmap and budgeted for three additional FTEs in 2015, as discussed in UE 283 (PGE Exhibit 600), and one additional FTE for 2016 in order to achieve the roadmap's timeline. This effort is also based in part on The Oregon Resilience Plan, issued in February 2013, 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).[6]

C. Support Services

Q. Please explain the cost increases for corporate safety, training, and staffing services.

A. PGE's costs for these support services are forecasted to increase from approximately $2.8 million to $4.4 million from 2014 to 2016. These increases are important for PGE to provide the necessary support for some of our core commitments and challenges.

Q. Please discuss PGE's company-wide safety focus.

A. PGE is committed to providing a safe and healthy place of business 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.

Q. What new 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 accidents, PGE is taking the following steps for 2016:

- One FTE is required to support the audit of PGE's safety programs, provide technical writing support and general support of new and existing safety programs and practices;
- Increasing the administrative and analytical support for PGE's new safety reporting system in order to realize the system benefits of improved safety metrics analysis, incident reporting, and anonymous "near-miss" reporting;

[6] The Oregon Resilience Plan is available at:
http://www.oregon.gov/OMD/OEM/osspac/docs/Oregon_Resilience_Plan_Final.pdf

- Developing a pre-qualification system to streamline the hiring of contractors; and
- Moving from divisional to company-wide compliance in the Occupational Health and Safety Administration's Safety and Health Achievement Recognition Program and Voluntary Protection Program.

Q. Please describe PGE's increase in staffing.

A. Since 2013, PGE has seen a continued increase in the volume of hiring, placing increased demands on the current staff beyond their capacity, reducing their effectiveness and lengthening PGE's time-to-fill ratio. Additionally, with a high level 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 improving economy has increased the difficulties in attracting, recruiting, and retaining these in-demand professionals.

Q. How is PGE addressing this gap?

A. To address the gap and maintain recruiting competitiveness, Staffing Services is increasing its outside services support for 2015 and 2016. This increased support will serve to reduce demands on current Staffing Specialists, allowing them to increase focus towards reducing the time-to-fill ratio through an increased guidance of the selection process for management and greater engagement in critical proactive recruiting strategies. Examples of recruiting strategies include career fair promotion and attendance, data-driven analytics, college internships, line pre-apprenticeship programs, and social media networking.

Q. Are there specific programs to address the retirement of senior professionals?

A. Yes. As discussed in PGE Exhibit 500, Staffing Services manages a critical workforce development program to assist with the training, development, and integration of newly hired employees who replace retiring employees holding highly specialized and critical positions within the company. The critical workforce development program provides funding and support for in-depth one-on-one training between the exiting employee and his or her newly hired replacement, ensuring critical knowledge transfer between retiring and incoming employees. Knowledge transfer with regard to critical positions is a major concern for PGE and other utilities.

Q. How have PGE's training needs changed over the last couple of years?

A. Since 2013, the demands for training have been increasing as PGE continually implements and integrates new systems and programs, while also relying less on over-burdened subject matter experts to provide training and develop curriculum. Because of this, the current training staff is unable to meet PGE's increased training requirements. To help address this issue, PGE is adding one FTE in 2016 to support 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;
- New engineer curriculum for Transmission, Distribution and Generation engineers; and
- Company-wide skill track creation and maintenance.

V. Conclusion

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

A. We request that the Commission approve the following:

- PGE's forecast of $160.0 million in A&G costs in the 2016 test year. This represents a $3.8 million increase from 2014 costs and is primarily driven by increases in employee benefits (i.e., health care and dental premiums), environmental and licensing services, insurance, and research and development.
- PGE's total IT forecast of $71.2 million in the 2016 test year. This represents an $18.1 million increase from 2014 and is primarily driven by costs associated with PGE's 2020 Vision program, higher software and hardware licensing and maintenance costs, and escalation.

Absent cost increases for employee benefits, environmental and licensing services, insurance, research and development, and IT (plus the increase associated with OPUC fees), PGE has reduced its 2016 A&G forecast with an overall annualized 6.8% cost decrease from 2014.

VI. 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 named vice president and chief information officer in 1998. 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.

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	2016 R&D Project Detail
605	IT O&M Cost Summary by Operating Area

A&G Summary

	Costs ($ millions)							FTEs						
	2012	2013	2014	2015	2016	2014 to 2016		2012	2013	2014	2015	2016	2014 to 2016	
Category	Actuals	Actuals	Actuals	Budget	Forecast	$ Delta	Annual %	Actuals	Actuals	Actuals	Budget	Forecast	$ Delta	Annual %
Major Functional Areas														
Facilities and General Plant Maintenance	4.8	4.2	5.5	4.9	5.2	(0.3)	-2.7%	12.9	12.8	12.9	13.3	13.3	0.4	1.6%
Accounting/Finance/Tax	9.1	9.3	9.7	10.1	10.4	0.8	3.8%	72.3	68.8	69.9	73.7	73.6	3.7	2.6%
HR/Employee Support (net of capital allocs.)	6.5	7.5	9.2	10.0	10.2	1.0	5.4%	103.7	103.9	107.8	109.5	111.5	3.7	1.7%
Insurance / I&D	11.5	11.0	8.5	12.7	11.3	2.8	15.4%	6.6	6.7	6.9	7.0	7.0	0.1	0.6%
Legal	5.2	4.8	4.6	6.3	6.1	1.5	15.1%	25.0	24.0	22.6	24.9	24.9	2.2	4.8%
Regulatory Affairs	2.3	2.7	2.6	3.1	3.2	0.7	12.6%	32.0	31.4	30.0	35.0	35.0	5.0	8.1%
Corporate Governance	3.5	3.6	4.1	4.4	4.5	0.4	4.8%	17.3	17.2	16.7	17.2	17.2	0.6	1.8%
Business Support Services	2.8	2.7	2.7	2.7	2.9	0.2	4.4%	7.0	7.0	7.0	7.5	7.5	0.5	3.5%
Environmental Services	2.6	3.2	2.7	4.4	4.6	1.9	30.5%	-	-	-	-	-	-	#DIV/0!
Corporate R&D	0.9	0.9	1.3	1.4	3.1	1.7	53.0%	1.0	1.0	1.7	1.0	1.0	(0.7)	-22.2%
Contract Services/Purchasing	1.3	1.3	1.2	1.0	1.1	(0.1)	-5.5%	22.0	20.5	14.3	14.0	14.0	(0.3)	-0.9%
Security and Business Continuity	1.3	1.4	2.0	2.1	2.7	0.6	14.2%	8.6	10.9	11.4	15.0	16.0	4.7	18.7%
Corp Communications/Public Affairs	2.7	2.1	1.9	2.0	2.2	0.3	7.1%	25.7	25.1	23.4	26.8	26.8	3.4	7.0%
Load Research	0.3	0.2	0.2	0.1	0.1	(0.0)	-12.2%	-	-	-	-	-	-	#DIV/0!
Hydro Licensing and Support	0.0	0.1	0.1	0.1	0.1	0.0	23.7%	-	-	-	-	-	-	#DIV/0!
Performance Management	1.3	1.3	1.5	1.8	1.9	0.3	10.3%	14.7	15.7	15.2	16.0	16.0	0.8	2.7%
Governmental Affairs	1.4	1.2	1.0	1.2	1.2	0.2	8.3%	12.4	10.1	8.5	11.5	11.5	3.0	16.5%
Subtotal	57.6	57.3	58.8	68.5	70.8	12.1	9.8%	361.1	354.9	348.1	372.3	375.3	27.2	3.8%
Other A&G Costs														
IT: Direct & Allocated	11.6	11.6	10.2	12.0	12.4	2.2	10.2%	249.8	238.1	234.8	251.3	261.3	26.5	5.5%
Corporate Cost Reductions	-	-	-	(2.2)	(3.0)	(3.0)	#DIV/0!				(18.1)	(24.8)	(24.8)	#DIV/0!
Other Membership Costs	2.0	2.4	2.4	3.4	3.3	1.0	18.5%							
Incentives	15.4	15.6	21.2	23.5	9.9	(11.4)	-31.8%							
Severance	1.0	0.9	0.0	-	0.2	0.1	106.8%							
Regulatory Fees	6.1	6.0	5.9	6.0	8.3	2.4	19.0%							
General Plant Maint.	2.9	2.6	2.3	2.6	2.4	0.0	0.5%							
Total PTO to A&G	5.2	5.4	5.3	5.7	5.9	0.5	5.0%							
Benefits (net of capital allocs.)	48.1	52.4	52.3	52.8	54.8	2.5	2.4%							
Corp Allocations	(6.1)	(3.7)	(4.1)	(5.6)	(6.8)	(2.7)	28.2%							
Revolver Fees, Margin Net Int., & Broker fees	2.0	2.3	1.8	2.4	1.8	(0.0)	-0.2%							
Subtotal	88.3	95.5	97.4	100.6	89.2	(8.2)	-4.3%							
TOTAL A&G	145.9	152.8	156.2	169.1	160.0	3.8	1.2%	610.8	593.1	582.9	605.6	611.8	28.9	2.5%
Match	-	-	-	-	-			-	-	-	-	-		

Exhibit 602

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 $800 million with a $2.5 million deductible.
Renewable Property	The All-Risk property insurance program for PGE's renewable assets is currently placed in the London market. Operational All-Risk coverage for these assets, including both wind and solar, are insured to their combined full replacement value of $960 million 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 a $1 million SIR. The limits purchased are reasonable and 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. (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.

Insurance Policy	Description
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 SIR
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, FTC. PGE purchases a limit of $10 million with a $.25 million SIR
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 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 its Workers' Compensation obligations.

Exhibit 603C

Confidential

Exhibit 604
2016 Proposed Corporate Research & Development Projects

Project Synopses	Cost
Project Categories	
Page 1 - Energy Storage (ES) **Page 2 - Operational Efficiency (OE)** **Page 5 - Renewable Projects (RP)** **Page 7 - System Resiliency (SY)** **Page 8 - Smart Grid (SG)** **Page 13 - System Reliability (SR)**	
ENERGY STORAGE (ES)	
5. Pumped Storage Geotechnical Assessment Research Description and Benefits The project performs static and dynamic Geotechnical evaluation of a potential pumped storage site. This may provide the basis for purchasing a site for a future Pumped Storage Hydro project. A local pumped storage hydro project could be used to support PGE's ancillary services for intermittent renewable resources. Risks of Non-Participation PGE and its customers would miss the opportunity to assess a pumped storage facility to help mitigate intermittency of wind and solar renewable power and thus help PGE meet Oregon's Renewable Energy Standard.	$17,000
6.Identifying Optimum Energy Storage Locations in PGE's Service Territory Description and Benefits This project engages with Oregon Institute of Technology (OIT), Portland State University (PSU) and or Oregon State University (OSU) either singly or in partnership to evaluate PGE's Service Territory to determine the optimum location of and type of energy storage devices. This is in anticipation of continued high penetration of distributed renewable energy production in the form of intermittent wind and solar power generation. This will allow PGE staff to assess the best approaches to smooth out peak energy demands on System feeder lines. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential to use energy storage strategically and in a distributed manner so as to mitigate the intermittency of wind and solar renewable energy to help meet Oregon's Renewable Energy Standard.	$42,300
44. Coupling Energy Storage with Other Smaller Scale Grid Applications Description and Benefits The US DOE notes that energy storage applications can be closely coupled to smaller scale applications such as Demand Response Programs for peak shifting; Integration with Electric Vehicle Infrastructure for energy storage & peak shifting; Commercial Building integration to optimize energy use, supporting Peak Energy Shift and Integration with Residential Use cycle(s) for peak shifting. In these smaller applications, there needs to be something in it for the host facility which usually translates into an acceptable return on investment and or the delivery of a feature that is important to the facility owner. These might include creation of microgrid capability that often involves significant local energy storage capability. PGE proposes a research project that would deliver an authoritative review of highest and best uses for energy storage on PGE's system beyond support for load levelling. The review will include opportunities and drivers on both sides of the meter. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for combining energy storage options with customer applications that can also be supportive of PGE grid operations.	$33,800
62. Evaluating Used EV Batteries for Stationary Power Use Description and Benefits As electric vehicle (EV) technology evolves, there is interest in obtaining EV batteries that are no longer suitable for a mobile duty cycle but are likely to have sufficient life to be used for other purposes. PGE notes that the Salem Smart Power Center (SSPC) facilities could accommodate testing between 250 kW and 1 MW worth of used EV batteries. The most straightforward approach would be to disconnect the equivalent amount of presently installed lithium ion batteries and do a direct 1 for 1 replacement if the present manufacturer had this type of battery resource available. Failing that, it would be best to test the	$143,800

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
available EV batteries (from a different manufacturer) using a separate inverter that can be matched appropriately to the output of the battery being tested. This can be done in 250 kW blocks. PGE has identified a dozen use cases under development for the current battery-inverter system (BIS) at the SSPC. This demonstration is to be supported by a project partner with knowledge of EV batteries; comprehensive knowledge of EV battery control and management and good familiarity with the EV battery market. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for lightly used EV batteries in stationary power applications.	
Total Energy Storage	**$236,900**
OPERATIONAL EFFICIENCY (OE)	
10. SSPP 400 kW of Demand Response Benefit (DR) <u>Description and Benefits</u> Two of the assets demonstrated as responsive to the transactive incentive signal included demand responsiveness involving: (1) twenty radio-controlled residential water heaters and (2) 51 commercial entities that volunteered to participate. Control for these assets involved automated interaction with PGE's Smart Power software platform and a "human in the loop" control to ensure a smooth experience for participating PGE customers. To involve the BIS in a manual routine demand response role is straightforward. If an automated DR is desired as is likely to be the case, this would incur need to produce a software control program. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS power proportion is rational – at present 400 kW of demand response power is projected as reasonable. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for using the SSPP battery inverter system in a demand response application.	$8,500
11. SSPP 1.3 MWh of Energy Shift from on-Peak Costs to Off-Peak Costs <u>Description and Benefits</u> As part of the demonstration, the ability to shift energy from on-peak to off-peak costs was effected. At the conclusion of the Demonstration and in the event that a regional transactive control center no longer exists to carry the demonstration further – then control would be simplified to target just a peak shifting function. This would incur a small cost to create (or possibly modify) a much simplified, automated control rubric. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS energy proportion is rational. At present, 1.3 MWh of energy shift capability appears reasonable but this may change with further study. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for the SSPP BIS to help reduce peak demand.	$25,400
14. SSPP ≈ 1.2 MWh of Off-Peak ability to Absorb Excess Wind Power <u>Description and Benefits</u> It is possible to use the BIS to absorb excess wind generated energy. It would require obtaining an appropriate signal from a wind generation facility. In 2013 this feature was conceived and incorporated as part of a PGE capital job that involved the test emplacement of an advanced LIDAR anemometry instrument atop a wind turbine at PGE's Biglow Canyon Wind farm. Upon successful completion it remains to assess its valuation and at what battery inverter system (BIS) energy proportion is rational. At present absorbing 1.2 MWh of excess wind capacity appears reasonable but research is advisable. In particular, PGE will convene a scoping discussion with university allies to: (1) get a better handle of this notion; (2) ensure BIS controls are adequate and fully automated and (3) design a research protocol with subsequent evaluative report to independently assess the overall efficacy of the effort. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for the SSPP BIS to help	$29,600

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
meet Oregon's Renewable Energy Standard.	
23. Developing a Hot Stick Inspection Tool Description and Benefits This project develops a tool that utilizes a hotstick, camera and recording device that can be carried by a single-man crew to visually inspect defects in the energized space such as wood pecker holes or damaged conductors. We expect initial design and electrical ground testing in 2015 with field crew test and evaluation in 2016. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for creating a new tool to make single man crews more operationally efficient.	$8,500
27. Developing a Mobile Temporary Foundation Description and Benefits PGE would like to develop a mobile concrete foundation that can be used to support temporary structures. The foundation would be cast out of concrete and designed to support a variety of poles. This would be most useful in setting poles quickly and in areas where ground disturbance would best be kept to a minimum. PGE staff may collaborate with the OSU Material Sciences Department for this work where there are several Professors who specialize in concrete applications. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for improving the efficiency of its field crews in setting temporary pole structures.	$17,000
28. Improved Construction Framing for Conductor Stringing Description and Benefits PGE would like to develop a series of distribution cross-arms that can be used to enhance the conductor stringing installation process both from mechanical and safety perspectives. Presently, when a crew needs to remove existing conductor and install new conductor (all the while keeping the existing circuit electrically active) they spread the existing conductor out onto "hot arms". In this event the "hot arms" are potentially not of sufficient rating to be able to support the size of conductor that is being removed. This causes the crews to use non-standard construction techniques which may or may not be rated for the type of loads the crews are encountering. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential to improve and standardize the conductor stringing operation.	$17,000
37. Determining the Best Foundation Grounding Approaches Description and Benefits PGE proposes a project to research the best methods to ground its steel transmission structures, including lattice towers and tubular steel poles. The research will include evaluation of the potential for moisture to wick into concrete via "stranded pieces" of copper conductor. The research should identify industry best practices to better inform current PGE grounding practices. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for improving foundation grounding for its steel transmission structures.	$17,000
40. Developing a Self-Leveling Camera/Mandrel Inspection Method Description and Benefits PGE proposes research to support the development of a tool that can serve as both a means to "proof a conduit" by mandrel and do a visual inspection at the same time. The research envisions mounting a self-leveling camera to a mandrel to be used in various conduit sizes to ensure physical integrity prior to field commissioning. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for improving its inspection	$8,500

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
ability to proof a conduit by using a combination of self-leveling camera and mandrel.	
41. Drone Inspections for PGE Transmission Lines – "Proof of Concept" Description and Benefits PGE proposes a research project to serve as a "proof of concept" for using airborne drones as an inspection tool for Transmission Lines. The project would include procuring a drone, mounting a camera to the drone, and testing the concept at an approved testing location, such as currently available at Warm Springs or at the Boardman Bombing Range. Drone inspection and monitoring has been put to good effect in other industries, e.g., crop monitoring in agriculture. Such a review can be conducted by a Pacific NW research university to set the stage for a trial demonstration. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for using a drone with mounted camera to reduce costs in transmission line inspections.	$12,700
46. Investigating Use of Ductile Iron Poles for T&D Infrastructure Description and Benefits PGE will explore the use of ductile iron poles to support overhead transmission and distribution facilities. Ductile iron is notable due to its minimal environmental impact and low cost. This is a forward looking effort in response to environmental regulations becoming increasingly more stringent and the need for PGE to meet the challenging demands of fiscal and environmental responsibility. Ductile iron poles are currently being marketed for use as utility poles, and while this material has historic use for underground water systems in many locations around the world (Europe and elsewhere), little is known about the material's long-term performance as utility poles. PGE may engage the research capabilities of Oregon State University's College of Civil Engineering. This will include a literature review as well as accelerated testing of ductile iron pole sections conducted under at least three types of degradation scenarios. PGE will provide the desired sections of ductile iron pipe for testing. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for obtaining arms-length research assessment for functional use of ductile iron poles to replace chemically preserved wooden poles.	$25,400
54. Use of Aqueous Hybrid Ion (Aquion) Battery in a Residential Duty Cycle Description and Benefits As PGE experiences increasing penetration of distributed renewable power generation in the form of 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. It is increasingly clear that energy storage on both sides of the customer meter will be needed to help store energy when it is abundant and to release it when it is needed the most. Promulgation of energy storage devices also enables the grid to proactively respond with demand side controls to limit peak power demand. If available in sufficient capacity, energy storage devices can help resolve the present "non-dispatchability" of wind and solar power assets. Emplacement of appropriate battery energy storage or other energy storage devices at residential locations is one of these possibilities. PGE has collaborated with PSU's Electrical and Computer Engineering (ECE) Department to take steps in this direction. This collaboration is considering use of a very safe and sustainable aqueous ion battery (7 to 8 KW inverter and the nominal 50 kWhr battery) that has more energy density than power density and would be suitable for household use. Risks of Non-Participation PGE and its customers would miss the opportunity to vet the potential for a safe, high energy density battery in a residential setting.	$127,000
55. Displacing Substation Pb-Acid with Long-lived Aqueous Hybrid Batteries Description and Benefits PGE T&D staff wants to test the Aquion Battery [C-NaMnO] as a potentially suitable replacement for lead acid batteries in substation applications. Early reviews of electrical requirements suggest that with the addition of a small supercapacitor (to help meet instantaneous peak power requirements), the Aquion Battery appears to be a suitable solution. This project will acquire batteries for testing as well as outside engineering to test the concept in at least one PGE substation. The Aquion Battery has a much wider	$33,800

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
voltage range of operation than lead acid batteries so part of the research will need to determine if a dc to dc voltage regulator might be required. The Aquion Battery is composed of common and non-toxic materials - which upon scaling to mass production - promise to make this battery cost-competitive very & sustainable. The Aquion battery line has higher cycle life when compared to present lead (Pb) acid battery technology. These characteristics i.e.: benign electrochemistry; much longer cycle life, cost-competitiveness makes the Aquion battery line an excellent candidate for not only utility use but also for residential applications. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for a high energy density and safe aqueous battery to displace lead-acid at substations.	
57. Advanced Waste Heat Recovery <u>Description and Benefits</u> Although abundant low-grade waste heat is available in coal-fired power plant flue gas, little progress has been made to utilize it due to potentially greater negative impacts (e.g., heat removal lessens the ability of flue gas to rise up and then out of the stack). PGE in collaboration with the OSU School Mechanical, Industrial and Manufacturing Engineering (MIME) seeks to evolve a low-cost, high-effectiveness, small-profile "2D" heat exchanger. The heat exchanger will be designed, built and tested to recover not only thermal energy in the flue gas, but also condense water vapor to use it as plant make-up water. The small-profile design in the direction of flue gas flow will have very little impact on the current exhaust system in terms of back pressure and energy consumption. The efficient water recovery around the heat exchanger will also prevent potential corrosion downstream. Upon successful demonstration, this concept can be used to maximize heat recovery from power plant flue gas and reduce water consumption in power plants while having little impact on current plant operations. This research and device development will provide an option for PGE to improve Boardman plant energy and water use efficiencies. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for improved power plant efficiency through waste heat recovery and re-use in applications that would otherwise require fuel to deliver working heat.	$33,800
Total Operational Efficiency	**$364,200**
RENEWABLE PROJECTS (RP)	
1. OSU Wave Energy <u>Description and Benefits</u> 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 Center (NNMREC) open ocean test berth – Pacific Marine Energy Center (PMEC). This will demonstrate and expand the available renewable resources for PGE customers using this renewable energy source. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate renewable wave energy devices as they are tested locally to help meet Oregon's Renewable Energy Standard.	$21,100
2. OSU Wind Integration <u>Description and Benefits</u> This project will develop an analytical Model in collaboration with OSU School of Engineering that optimizes the use of existing Pacific Northwest resources to help integrate renewable resources. This will allow better use of existing PGE wind resources and help inform PGE of future Capacity needs involving renewable wind power especially through improved scheduling and wind forecasting. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for renewable wind energy to help meet Oregon's Renewable Energy Standard – especially in the possibility of staggering or	$21,100

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
optimizing wind resources to reduce capacity needs.	
3. U of O Solar & Meteorological Data Collection/Evaluation Description and Benefits This project supports the University of Oregon's 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. Risks of Non-Participation PGE and its customers would miss the opportunity to obtain more granular solar insolation data in preparation for more distributed solar energy development on PGE's grid.	$16,900
4. PSU Wind Tunnel Optimization Studies for PGE Wind Farms Description and Benefits This project proposes research to optimize the blade length and rotor rotation for the Siemens wind turbines at PGE's Biglow Canyon Wind Farm. This research results will potentially increase the performance/output at PGE's Biglow Canyon Wind plant. The optimization research and resulting power modelling validation would utilize the wind tunnel available at Portland State University. Risks of Non-Participation PGE and its customers would miss the opportunity to optimize Biglow operations so as further capitalize on PGE's substantial installed wind capacity.	$21,100
7. Biglow Canyon Solar Investigation Description and Benefits This project performs a case study to determine the capacity for a utility scale 5 – 10 MW solar project at PGE's Biglow Canyon Wind Farm. One wind collection string – in the Central-South side (sites 348-351), near the Wasco Airport – is currently under-utilized due to the Federal Aviation Administration's (FAA) dis-allowance of wind turbine towers at four (4) wind foundation locations. The research will be accomplished by Black and Veatch (B&V). This project might also involve the University of Oregon for solar insolation data. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for renewable solar energy to help meet Oregon's Renewable Energy Standard and in a location that has already had substantial permit reviews.	$42,300
47. Pre-Feasibility Study – Low Head Hydrokinetic Device Description and Benefits PGE has performed preliminary due diligence on a potentially viable low head hydrokinetic power generators. PGE has interest in the unit capable of 400 kW of power generation. The manufacturer is a Canadian Company. Their 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 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 or survive interaction. This project seeks to characterize a possible riverine or canal location for demonstrating this device as part of PGE's renewable power generating infrastructure. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for using renewable low-head hydro energy to help meet Oregon's Renewable Energy Standard.	$76,100

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
48. Biomass Torrefaction and Combustion Studies at Boardman Description and Benefits Since 2010, PGE has embarked on a large R&D effort to assess the feasibility of displacing coal at its Boardman pulverized coal plant with biogenic 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 and 100% torrefied biomass applications. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for renewable biomass energy to displace coal at PGE's Boardman Power Plant to help meet Oregon's Renewable Energy Standard.	$253,900
53. Arundo and other Biomass Agronomy Description and Benefits PGE has pursued agronomic research of the fast-growing, perennial grass Arundo donax in both academic and full-field test conditions beginning in 2011. This also included similar scale testing for Sorghum - an annual crop that may be suitable traditional crop rotations in the north-central region of Oregon. PGE has also torrefied and analyzed 26 other biomass materials in order to ensure an adequate assessment of a wide variety of material that might be usable as torrefied biomass fuel to displace coal at PGE's Boardman Power Plant. In 2014 PGE demonstrated the full-field eradication of Arundo to fulfill a public commitment to the Oregon Department of Agriculture to ensure that this could be done successfully at > 45° north latitude. Also, Oregon State University completed a comprehensive study on Arundo agronomy at this same latitude. In 2015 and 2016, PGE intends to reduce planting acreage from the two current irrigated circles to just one 30 acre circle. In these two years, PGE needs to demonstrate the ability to store collected Arundo rhizomes over a winter in order to supply new planting material the following spring. Finally, PGE needs to continue an important study on the effect of planting density on Arundo productivity (tons per acre). Risks of Non-Participation PGE and its customers would miss the opportunity to fully investigate the potential for renewable biomass energy to help meet Oregon's Renewable Energy Standard.	$72,000
Total Renewable Projects	**$524,500**
SYSTEM RESILIENCY (SY)	
35. Seismic Capacity on PGE Transmission Lines Description and Benefits PGE proposes a comprehensive study to evaluate the transmission system effects from a range of potential seismic events. The research would include evaluation of PGE's entire system of towers, foundations, insulators, and conductors. The research will identify industry trends; best practices for applying to PGE's infrastructure in a prioritized manner. Factors for consideration include, age, materials, weathering, design, other. The study should highlight potential strengths and weaknesses. The research will also identify and prioritize with PGE's review and concurrence, recommendations for mitigation, strengthening and other opportunities to improve transmission system resilience in response to seismic events. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate potential mitigation for significant infrastructure impacts possible from a range of seismic events.	$84,600
61. Cascadia Lifelines Research – OSU Description and Benefits The Cascadia Lifelines Program provides essential and unique engineering solutions for lifeline providers. This includes devising cost-effective retrofit strategies for the region's infrastructure that will subjected to long-duration shaking resulting from a Cascadia Subduction Zone event.[1] The project provides improved	$38,000

[1] A Cascadia Subduction Zone event is likely to exceed 8.5 on the Richter scale and happens in the region on average, every 300 years

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
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 research assesses cost-effective approaches to increased infrastructure resilience for western Oregon and PGE's service territory. R&D funding of $50,000 per year for a 5-year commitment or $250,000 over five years allows PGE to occupy a seat on the management board that guides the OSU research priorities. The dollar commitment on behalf of PGE customers is matched 5 to 10-fold from other utility and related infrastructure providers (e.g., BPA, ODOT, NW Natural, EWEB, Port of Portland and others). <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to acquire a better understanding of lifeline infrastructure impacts due to a Cascadia Subduction Zone event. The missed opportunity would also include the highly leveraged participation of other lifeline providers participating in this research. This is especially important as such research cannot be done in a vacuum.	
Total Resiliency Projects	**$122,600**
SMART GRID (SG)	
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. Listed below are explanations of some of the future R&D Projects that evolved from the SSPP.	
9. SSPC Battery Inverter System (BIS) - Response to Transactive Incentive <u>Description and Benefits</u> The BIS has operated under automated transactive control for over a year. With the project's completion at close of 2014, there has been interest from the regional smart grid community in the continued development of a regional transactive control system. This is driven by three factors: (1) efficient control of demand response resources; (2) improved management of increased penetration of distributed intermittent renewable power from and (3) the need to balance on a transactive basis increasingly shorter periods of energy supply and demand. This project proposes to focus expressly on using the SSPC BIS in a transactive control setting that is either regional or within a PGE setting. The research should support more advanced development of a regional energy imbalance market (EIM). <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to participate in the continued development of advanced transactive control software help meet Oregon's Renewable Energy Standard.	$63,500
15. SSPP: 5 MW Load Response to Under-voltage Load Shedding Event <u>Description and Benefits</u> This capability has already been demonstrated as one of the asset functions delivered by PGE in its contractual obligation as part of the Pacific NW Smart Grid Demonstration Project. This effort culminated in the creation of a high reliability zone (HRZ) whereby 1 MW of power was supplied to the feeder under a load shedding scenario. The BIS served as the intermediary to ensure that load could be picked up instantaneously during the shedding event. To complete the high reliability rubric, power supply was then smoothly transferred to a temporary 1 MW diesel power generator that had been attached to the feeder.[2] This project is to fine tune the capability and to consider building autonomous control into its operation in anticipation of more energy storage device use on PGE's grid. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for additional microgrid capability on PGE's system.	$38,000

[2] Although PGE used a 1 MW diesel generator to perform this function, the SSPP Smart Power Platform has the capability to engage three of PGE's dispatchable standby generators (DSG) in this same role. This ability to tie in the DSG resource via transactive energy control was also demonstrated as part of the Pacific NW Smart Grid demonstration project.

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
16. SSPP Real-time Solar Integration Utilizing PV Solar Output Signal Description and Benefits Kettle Brands potato chip factory graciously allowed PGE to obtain the output signal, via radio from its 114 kW roof-mounted solar photovoltaic (PV) system. This signal, in combination with the ability to either store or release energy via the SSPP battery inverter system (BIS) is then used to: (1) Reduce peak load on PGE's Rural feeder line and (2) Reduce significantly, the load variation on the feeder to be more in line with the historically-modelled "ideal" load curve. These outcomes are attractive as they reduce the wear and tear on PGE's substation transformers[3] and at the same time helps integrate the intermittent output that is characteristic of solar PV systems. This project extends the initial demonstration via: (1) creation of autonomous controls; (2) underlying studies on the conditions for initiation; (3) formal documentation of net system benefits/effects and (4) potential connection with multiple distributed solar generating systems. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for using the unique SSPP BIS to integrate renewable solar energy to help meet Oregon's Renewable Energy Standard.	$16,900
17. Frequency Response Test and Deployment Description and Benefits This use has already been demonstrated at the specific request of PGE's Transmission Services Department.[4] In completing this demonstration, a frequency regulation screen was created to allow an operator at the SSPP control room to enter frequency setpoints (high and low) to which the BIS will respond. The operator also has the option to select the power level in response to an event— up to 5,000 kW. Although 5,000 kW is within the capability of the SSPP BIS, the setpoint is generally held to 3,000 kW to ensure that the lithium ion battery is not fully discharged in order to help preserve its expected life. With setpoints in place and response maximum in play, the SSPP BIS can be set to automatically respond to unexpected frequency excursions. This Project will accomplish new autonomous and remote controls for the operation of the SSPP in this mode; later work will fine-tune the controls. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the unique capability of the SSPP BIS to help mitigate a pending NERC requirement for system frequency support.	$25,400
18. Distribution Automation Using Advanced, Intelligent Switches Description and Benefits Four advanced "Intellirupter Switches" made by S&C Corporation were installed by PGE as one of the five asset deliverables for the Pacific NW Smart Grid Demonstration project. These relays are strategically placed on the Rural Feeder to allow automated switching control in the event of a fault in some portion of the line. These relays can routinely and rapidly query the line with time-stamped pulses to ensure continuity and to quickly localize a fault. These switches have been tested and shown to be responsive to transactive energy control. Nonetheless, there is much more that should be explored to fully utilize their capabilities especially in fault isolation where instead of the entire feeder being rendered off line in response to a fault, the use of these switches would isolate only the affected portion of the line. An R&D project has been scoped to further automate and incorporate the use of these switches on PGE's grid. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for smart switches to help reduce customer outages.	$38,000

[3] For example: Fewer tap changes in response to less voltage and feeder load demand variability

[4] PGE's Transmission Services requested as well as provided the incremental funding for this initial demonstration; the effort is in anticipation of a rapidly developing NERC rule on the need to respond adequately to an off-normal frequency "event". In PGE's experience – this is especially useful in an under frequency occurrence.

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
19. Adaptive (Dynamic) Conservation Voltage Reduction Description and Benefits This use is similar to static conservation voltage reduction (CVR) except that with the Salem Smart Power Center's (SSPC) battery inverter system (BIS) in play it is possible to reduce voltage (and thus power) adaptively over the entire length of the feeder line. This is much more attractive inasmuch as feeder loads can come on and off at many different locations on the feeder and not just at one spot. Thus, this has the potential to yield higher energy savings to benefit PGE's customers. The approach would be to use existing metering on the Rural Feeder line to develop a feeder voltage profile. Following that, the Oxford substation voltage regulators can be temporarily disabled so that the SSPC inverters can assume the voltage regulation function. The goal is that during times of peak or unexpected demand, voltage can be regulated lower dynamically to reduce the peak power and to more closely match the historical feeder voltage profile. This project will test this notion and if successful will create new autonomous and remote controls to offer this capability to PGE System Operations. Risks of Non-Participation With the successful integration of the SSPP BIS - PGE and its customers would miss the additional opportunity to investigate the potential for the BIS to provide a more advanced form of conservation voltage reduction (CVR).	$25,400
20. Using the SSPP as a Dispatchable Standby Generation Resource Description and Benefits Presently, PGE has nearly 100 MW of capacity contracted for use as dispatchable standby generation (DSG) during periods of extraordinary peak power demand. In this arrangement, all of the consenting facilities deploy backup diesel-powered reciprocating engines that are capable of rapid startup as well as black start (zero power) use. The BIS has the ability to provide this same service and could add 5 MW to this DSG tally. This would require that control software be replicated to integrate this resource as part of PGE's DSG proprietary GenOnSys control and operations package. Essentially this would reproduce operational control of the SSPP BIS to the DSG control center located in Portland. The early design for the SSPP BIS actually envisioned this remote control option so cost estimates are already available to accomplish this desirable ability. Upon completion it remains to assess its valuation and at what BIS power and energy proportion is rational. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for the SSPP BIS to function also as a dispatchable standby resource to help offset peak demand.	$25,400
42. Transmission and Distribution Analytics Pilot Description and Benefits For the period 2014 - 2016, PGE's Transmission and Distribution (T&D) Asset Management group would will initiate 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 and will be very economic based on initial cost assessments. It is also consistent with PGE's Smart Grid Roadmap. The overall cost estimate for the pilot beginning in 2014 is $300K; with actual implementation covering a 24 month period beginning in 2015 and extending into 2016. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for renewable wave energy to help meet Oregon's Renewable Energy Standard	$84,600
43. Survey of Distributed Power Gen, Grid-Scale Energy Storage Capability Description and Benefits With decreasing costs for communications and technology coupled with increased societal requirements for renewable power generation – there has been a notable move from centralized power to more distributed power generation resources such as solar and wind. The intermittency of these distributed power resources has also spurred a renaissance in grid-scale, energy storage devices to help integrate these intermittent	$25,400

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
renewable power sources. Early demonstrations of grid-connected battery energy storage, of which the lithium ion battery inverter system (BIS) at PGE's Salem Smart Power Center is an example, are now becoming more frequent. Early uses for these installations include firming and shaping wind and solar generation as well as frequency support. With this background, PGE proposes research that would culminate in an authoritative paper identifying the potential for locating energy storage installations as part of its grid specifically in response to high penetration of distributed renewable power. The paper would identify and discuss best practices, technical, siting and societal considerations. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the vast potential for distributed renewable energy to help meet Oregon's Renewable Energy Standard by combining this penetration with grid-scale energy storage.	
45. Assessing Energy Storage as a Transmission Alternative <u>Description and Benefits</u> It is well known that the Pacific Northwest transmission grid is congested – especially in east-west electricity movement but also in 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 the Bonneville Power Administration (BPA) controls 75% of the region's transmission system this is a top of mind concern. Since PGE has a heavy reliance (as do virtually all electric utilities in the region) on the BPA system it is also of import to the Company and its customers. The ability to construct new transmission lines is expensive 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. PGE proposes a competent and authoritative research paper to analyze this possibility in light of recent energy storage advances. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential better understand a non-wires solution using energy storage to help relieve regional transmission congestion.	$50,800
49. EPRI Program 161 Information & Communication Technology (ICT) <u>Description and Benefits</u> When advancing into the smart grid arena it is critical that PGE understand ICT requirements since a key ingredient of a "smarter grid" is the ability for faster communication, data acquisition and analysis. PGE has specific interests in ICT especially for the expected high penetration of distributed energy resources (DER). High DER penetration of renewable power like wind and solar imposes the need for grid response in managing variability through increased situational awareness. This can be exacerbated by increasing aggregation of multiple types of DER as well as demand response (DR) at both customer and utility locations. A good example is PGE's early work in with EPRI and water heater manufacturers in helping define interoperability standards for communications socket interface with residential water heaters. PGE expects more of this "intelligent appliance" technology to emerge and or be technologically transferred from research laboratories to commercialization. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the need for standard ICT requirements in supporting a variety of smart grid applications.	$73,660
51. Using the SSPC as a Smart Grid Energy Storage Test Facility <u>Description and Benefits</u> From 2010-2014, PGE successfully brought on line the Salem Smart Power Center (SSPC). Located there is a 5 MW battery inverter system (BIS) capable of storing 1.25 MWh of energy. This facility is owned by PGE and is used to test and demonstrate numerous energy storage concepts. PGE's effort required melding a battery supplier with an inverter supplier and ensuring that their respective control and monitoring systems were compatible. After that, there was substantial effort to write control and operating software	$125,900

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
and visualizations so that the BIS could be integrated into PGE's grid. PGE staff is now learning how the BIS can function operationally. In achieving this success, there is the opportunity to capitalize on the accumulated knowledge and to build on the success through performance of additional tests and demonstrations. The SSPC was designed to be a flexible research, development and demonstration facility. This project seeks to fine-tune and complete the SSPC as a complete energy storage test facility capable of supporting new applications. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for building on PGE's success at the SSPC and to extend its capabilities in testing other energy storage applications that can support PGE's grid operations.	
52. Evaluation of Operating Fuel Cells Description and Benefits PGE has investigated two active 5 kW fuel cells (FC) resident at Portland Community College (PCC Sylvania Campus) operating in a cogeneration configuration. These units are made by the now defunct ClearEdge Power and are phosphoric acid core FCs. We have learned that the FC stacks were replaced with a more robust design in 2013. As PCC is a PGE customer we propose to collaborate with PCC Administration, Faculty and Students to assess the performance of these relatively small units. PGE's proposed collaboration would also involve the Power Engineering Department at Portland State University (PSU). The investigation would include assessing, at a minimum: (1) Capacity factor, (2) Efficiency, (3) Routine Maintenance requirements with attendant costs, (4) Recommended Preventive Maintenance, (5) Durability, (6) Cycling flexibility, (6) Overall costs, avoided costs and related soft benefits. Failing an agreement with PCC, there is the potential for other options for these relatively new fuel cells. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential fuel cell applications especially in a co-generation application where the overall efficiency can be ≥ 80%.	$33,800
56. Hybrid Microgrid Creation with Full Island Capability Description and Benefits A unique asset delivered as part of PGE's participation in the Pacific NW Smart Grid Demonstration was the ability of the Salem Smart Power Project's (SSPP) lithium ion battery inverter system (BIS) to seamlessly support a fully islanded microgrid. In this scenario, the BIS could support the Rural Feeder line in the event of a frequency excursion induced by loss of energy supply to the Oxford Substation where the Rural Feeder drew its power. Subsequently, the battery could then be relieved of duty by three dispatchable standby generator (DSG) locations participating in PGE's larger DSG program resident on the same feeder line. These DSG's are diesel powered with more than sufficient capacity to supply both their own needs as well as PGE customers on the feeder. To better understand the nature of at least the technical requirements on a more generalized basis, this project seeks to model the important parameters, limiting conditions and scalability for creation of additional microgrids on PGE's system. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for building on present knowledge in microgrid creation and application – especially in areas that are prone to localized outages.	$46,500
58. Testing and Integration of Smart Inverter Functions Description and Benefits As electric utilities experience increasing penetration of distributed renewable power generation at the distribution feeder level, there is heightened awareness for the need to ensure acceptable power quality from both safety and reliability perspectives. The ability to respond quickly and automatically to voltage variations and frequency events helps ensure system reliability. This same ability also allows the grid to proactively respond with demand side controls to limit peak power demand. Inverters which transform DC to AC power when connected to energy storage devices can and increasingly do offer the capabilities to mitigate many of the concerns. These advanced inverters have been termed "smart inverters" or "four quadrant inverters" in deference to their flexible capabilities which in turn result from comprehensive programming that allows them to optimize energy storage and release to benefit either the system owner or	$36,400

Exhibit 604 **2016 Proposed Corporate Research & Development Projects**	
Project Synopses	**Cost**
the host utility or both. PGE in collaboration with PSU's Power Engineering group will compose research-based test protocols to define and document more precisely the benefits of smart inverter use and proliferation at scale on PGE's grid. Protocol development would take place in 2015 followed by documentation of one to two test cases in 2016. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for smart inverter proliferation on PGE's grid and to understand their abilities to support the grid in new, distributed applications.	
59. Joule Bank System (JBS) <u>Description and Benefits</u> This is a continuation of a unique, proprietary project started October 1, 2014 on the design and early prototyping of the Joule Bank System – a new, flexible, highly efficient, residential heating and cooling system based on heat pumps and thermal storage. Extensive collaboration has evolved on this project to ensure arms-length, third-party assessment. Collaborating institutions include Harvey Mudd School of Engineering for thermodynamic assessment and modelling; Portland State University for initial prototype design and development. Because of the thermal storage and utility control features, it is estimated that at scale, 90% of peak demand can be eliminated and the energy storage can be "filled" mostly at PGE's discretion. In 2015, PGE will conclude theoretical and prototype development; in 2016 – it is anticipated that a "production" model will be tested under real-world conditions. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for an innovative thermal storage + heat pump design that can have a meaningful effect in helping PGE offset peak demand.	$84,600
60. EPRI Collaborative Demo of DR-Ready Appliances <u>Description and Benefits</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 DR-ready appliances; mostly at 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.) With this proposal PGE intends to test demand response (DR) with hot water heaters and EVSEs. 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. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for introduction of DR-ready appliances at scale in PGE's system	$50,700
Total Smart Grid	**$844,960**
SYSTEM RELIABILITY (SR)	
8. Test and Demonstration of Port Westward HRSG Fouling Inhibitor <u>Description and Benefits</u> Since the Port Westward plant's initial startup in 2007, ammonium sulfate and bisulfate (ABS) deposits have been forming on the back end of the Heat Recovery Steam Generator (HRSG). ABS forms primarily due to high sulfur content in the fuel gas reacting with ammonia that is injected to limit gas turbine NO_x emissions. The resulting ABS salt deposits foul the HRSG tube heat exchange surface area, limiting power output of the gas turbine and subsequently degrading the overall operational performance of the HRSG. An economic analysis has identified lost value of approximately $1.2 million per year due to ABS fouling. Decreasing the salt formation by using a chemically fouling inhibitor will eliminate the future buildup of ABS, and reduce, if not eliminate, the lost efficiency that results from this fouling.	$21,100

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for eliminating the ABS fouling which would make the power plant more efficient. Port Westward is already one of the most efficient combined cycle gas turbine power plants in the west and this project would help maintain that position.	
12. SSPP: 2 to 4 MW of Real-time Voltage Support for System Operations Description and Benefits Using the SSPP for real-time voltage support requires more operational definition and research, but at a minimum the present SSPP controls might be replicated for manual PGE System Operations control. This could also be automated so that voltage control would respond without operator intervention. This use would be a first for PGE in terms of engaging a sizeable grid-tied energy storage device. Upon completion it remains to assess its valuation and at what BIS energy proportion is rational. At present, 2 to 4 MW of real-time voltage support using the SSPP BIS appears reasonable. Risks of Non-Participation PGE and its customers would miss the opportunity to fully automate PGE's only significant grid-tied battery installation to provide system voltage support.	$8,400
13. SSPP kVAr Support and control on the Distribution Feeder Description and Benefits PGE has implemented the Salem Smart Power Project's (SSPP) battery inverter system (BIS) which utilizes a smart inverter so it can already perform a kVAr support function but only under manual control. Fully automating this feature would utilize the full "four quadrant" capability of the smart inverter. This would extend the overall smart grid capability of the SSPP BIS but would require the creation and installation of basic control software. This use is entirely feasible would be a first for PGE in terms of engaging a sizeable grid-tied energy storage device for this purpose. Upon completion it remains to assess its valuation to PGE customers and at what BIS energy use proportion (maximum is 1.25 MWh) is rational. Risks of Non-Participation PGE and its customers would miss the opportunity to automate the 4-quadrant capability of the SSPP BIS to fully support PGE grid operations.	$4,230
21. EPRI Program 60 Electric & Magnetic Fields & RF Health Assessment, Safety Description and Benefits 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, 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. Program 60 provides PGE with research, analyses, and expertise to better inform public dialogue and regulatory oversight. Risks of Non-Participation PGE and its customers would miss the opportunity to stay abreast of the latest information on EMF safety.	$126,900
22 .EPRI Program 62 Occupational Health and Safety Description and Benefits The Electric Power Research Institute's (EPRI) Program 62 provides members with research in 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 OH&S 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; development of an exposure database; and SF6 decomposition by-products. The program is designed to address both current occupational health/safety issues and anticipate those of tomorrow.	$42,300

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
<u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to stay fully informed of the latest electrical industry trends and research in occupational health and safety.	
24. PGE Helicopter Mounted LiDAR Inspection of Transmission Lines <u>Description and Benefits</u> PGE spends several hundreds of thousands of dollars every year commissioning flights to gather LiDAR information as part of its Transmission Line inspection program. As an alternative, PGE proposes to research the possibility and viability for installing a LiDAR camera on the PGE Helicopter. Being able to capture LiDAR with our own camera on our own helicopter would aid significantly in the data acquisition process and should drive down costs. This project would include a proof of concept for mounting a camera and executing a test flight as well as developing a real cost analysis of LiDAR and, if successful, building a cost-effective business case. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for significant cost savings in using a LIDAR mounted system on PGE's helicopter.	$84,600
25. Assessing Thermal Profiles and Behavior in Conductors <u>Description and Benefits</u> PGE proposes to research the actual thermal behavior of a conductor including both along the span and throughout the cross-section. This research would allow a better understanding of the correlation between ampacity, conductor temperature, and span length under conditions specific to PGE's system. Understanding this behavior and characteristic can lead to better prediction of conductor performance and possibly pre-cursor metrics identifying potential failure. We anticipate utilizing support from academic allies or consultants in carrying off this project <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for improved inspection and correction for its conductors to both reduce conductor failure and or to predict failure prior to its occurrence.	$42,300
26. Developing an Effective Woodpecker Hole Patch <u>Description and Benefits</u> PGE needs to develop an effective fix to repair woodpecker holes as well as act as a possible deterrent for woodpecker damage. PGE identifies dozens of woodpecker holes in its poles annually. The only options to fix these woodpecker holes is to fill the hole with a foam (which provides no structural integrity or deterrent effect) or replace the pole entirely which is costly and again, provides no deterrent. Developing a permanent fix for the damage without replacing the poles would save thousands of dollars and hundreds of repair man-hours. It is likely that PGE will work with the OSU Utility Pole Consortium to accomplish this work. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for cost-savings by assessing an improved, effective hole-patch that provides both structural integrity and deterrence to woodpecker attacks.	$12,700
29. Inspection & Correction Program Development for Below Grade Corrosion <u>Description and Benefits</u> PGE desires to develop an inspection and correction program to learn more about below grade corrosion for its galvanized lattice towers, galvanized tubular steel poles and weathering steel tubular steel poles. The research will include a survey of industry best practices. Presently, the Company has very little experience evaluating the below grade condition of its steel structures. PGE will employ the services of 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. 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. This limitation yields existing corrosion rate measurement techniques	$71,900

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
inaccurate, unreliable, and in most cases, unusable in field applications. Research will include mitigation and correction methods including: below grade coatings, ground sleeves, grounding techniques, and cathodic protection. It is likely that BPA will contribute funds to expand the work (e.g., different soil types, tower designs, etc.). <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for improved inspection and correction program for below-ground coated steel.	
30. Deriving an Adequate Inspection Program for Aging Concrete <u>Description and Benefits</u> There are dozens of poured concrete pier foundations throughout PGE's Transmission system. PGE is interested in understanding more about the life span of the concrete used in those foundations as well as what physical and or chemical characteristics should be monitored proactively, to assess how best to inspect the piers. A deliverable from this proposed research would be to develop an improved inspection program including obtaining the tools and technology to inspect and if needed provide corrective actions for foundations with less than optimal indications. As an adjunct, this research also proposes to develop an improved set of specifications for both construction and long-term inspection for these integral construction members. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for an improved inspection and correction program for concrete piers especially as this component ages.	$21,200
31. Improved Cleaning Management of "Dirty" Insulators <u>Description and Benefits</u> PGE commits thousands of dollars every year washing insulators and replacing "flashed over" insulator bells. Thus, there is interest in evaluating the impact of a "dirty environment" e.g., dust, birds, and moss on the electrical and mechanical behavior of different insulator types (principally porcelain and polymer). This research project would include removing some insulators from service and testing their electrical behavior as well as "artificially aging" insulators and finding out how their electrical and mechanical properties as well as resistance to contamination may change over time. Oregon State University has extensive technical capabilities and interest in the accelerated aging of materials and has been consulted as to research both the concept and the approach. The goal of this research is to help PGE fine tune and ensure cost-effectiveness in its insulator cleaning and replacement program. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for developing an improved insulator cleaning and management program.	$42,300
32. Pre-Cursor Metrics to Assess Insulator Aging <u>Description and Benefits</u> PGE is interested in developing a strategy to measure the life of its in-service insulators (principally Porcelain, Polymer, & Toughened Glass). The idea is to further our understanding of pre-cursor metrics and proactive inspection to assess insulator in-service life. This will in turn, help inform future recommendations with regards to changing them as they approach the end of their life. As a goal of this research, PGE should be able to predict insulator failure prior to the manifestation of any reliability issues. <u>Risks of Non-Participation</u> PGE and its customers would miss the opportunity to investigate the potential for developing proactive metrics to predict insulator failure due to aging. Improved predictive capability would allow PGE to cost-effectively schedule and replace insulators prior to failure.	$21,200
33. Proactive Management of Chalking in Polymer Insulators <u>Description and Benefits</u> PGE has thousands of polymer insulators in service; of these, a fraction show signs of "chalking." This is described as the migration of alumina tri-hydrate to the surface of the insulator. PGE is interested in knowing more about this phenomenon and its impact on insulator life from both electrical and mechanical	$21,200

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
perspectives. This research proposes to study different insulator manufacturers and vintages and their subsequent in-field performance with regard to chalking. The research should develop a better understanding of this phenomenon to help inform and strengthen PGE's specifications and thus increase reliability of polymer insulators. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential to identify Polymer Insulator manufacturers that have the least chalking and thus improve system reliability due to less insulator failure.	
34. Corona Phenomenon Effects on Electrical Components Description and Benefits Corona is the process that occurs when the electrical field is so high that the surrounding air begins to breakdown. When this happens the air around the corona decomposes into ozone (O_3) and nitric acid (HNO_3).The nitric acid component can then eat away at any material present. Organic based materials are especially vulnerable to nitric acid attack. PGE is proposing research to better understand the effect of corona (nitric acid) on insulators, hardware, and conductors in order to better predict equipment durability and devise cost-effective countermeasures. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential to mitigate corona effects on system equipment and contribute to system reliability.	$33,900
36. Improved Inspection Approaches for Conductor Aging Description and Benefits PGE proposes research to better understand conductor aging; in particular the research would evolve approaches to learn how to better inspect and quantify the remaining life of a conductor. The research would include removing some conductors from service, performing tests on the conductor, and procuring available tools, based on best practices to better inspect and evaluate conductors that are currently in service. The research also contemplates using "accelerated aging" techniques as is available at Oregon State University (OSU). This approach can be used to simulate and better estimate risk of conductor failure where sampling removal is likely not an option; e.g. underground cabling. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for predicting conductor failure due to aging and attendant effects.	$59,200
38. Transverse Cross-arm Loading at Pole Connection Description and Benefits PGE proposes a study to determine the shear strength of typical wood poles at the distribution cross-arm bolt. At present, PGE standards limit the amount of transverse force on the cross-arm due to the potential for the bolt to "shear out" of the pole. PGE would like to develop a more definitive "force limit" on the cross-arm by empirically sampling and testing multiple poles and finding an optimal answer based on real cross-arms and poles in functional settings. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for improved pole construction by establishing a functional strength standard for pole cross-arms.	$33,800
39. Longitudinal Capacity of Wood Arms Description and Benefits PGE proposes a two-year research study to determine the longitudinal capacity of wood cross-arms in an effort to develop a cross-arm standard that will be able to support (with a safety factor) typical distribution loads found on PGE's system. Typical double heavy wood cross-arms are not capable of handling the loads associated with typical conductor loads and thus PGE has specified fiberglass cross-arms for these installations. PGE would like to further investigate the potential of double wood arms and see if the arms are sufficient or, if there is a relatively simple way to modify the arms to develop the required strength.	$42,300

Exhibit 604 2016 Proposed Corporate Research & Development Projects	
Project Synopses	**Cost**
Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential for improved pole construction by establishing a functional strength standard for wood pole cross-arms and potentially for reducing cost.	
50. Beaver Plant 4160 V Switchgear Temperature Monitoring Description and Benefits A PGE capital project is underway to replace the 4160V switchgear at PGE's Beaver combined cycle gas turbine generating plant. At this stage there is an opportunity to install remote temperature measurement sensors in several places. Over the life of the switchgear these measurements can be analyzed to research the locations in the switchgear that are prone to overheating. This monitoring has the potential to prevent failures and educate the company on possible weak points in the switchgear. Currently, regular maintenance outages are required to torque bus connections and inspect breaker connection points. Infrared monitoring and visual inspections are also used to look for hot spots. These methods require plant outages and exposure of personnel to potential arc flash hazards. This research opportunity will help PGE staff identify optimal locations for this type of sensor monitoring to prevent failure of switchgear, reduce maintenance activity, reduce plant outages and reduce hazard exposure to personnel. Success of this project should help reduce extended plant outages due to switchgear failure events and related maintenance work. Risks of Non-Participation PGE and its customers would miss the opportunity to investigate the potential of improved switchgear temperature monitoring via remote means.	$16,900
63. Developing a PGE Thermal Spray Coating Laboratory and Project Station Description and Benefits This project is intended to evaluate the effectiveness of thermal spray coatings for the repair and maintenance of PGE assets. The technology of applying molten metal layers to a metallic base substrate has been in continuous development in the USA for many years. Today there is an industry of companies devoted to supplying thermal spray coatings to customers with industrial and commercial applications. In recent years PGE has been able to see this technology in practice and some PGE assets have benefited from its application. This proposal provides a path forward for using this technology as part of our ongoing welding technology practices. R&D funding will be used to plan and outfit a thermal spray lab at an appropriate PGE facility with the intention of proving the technology on actual PGE asset repairs, training existing welders to utilize the technology for repairs, and document the concepts and practices for future use in repair documents. The thermal spray lab would be closely tied to PGE's current metallurgical lab so that each and every repair utilizing thermal spraying can be efficiently sampled and analyzed for adequacy of the intended function and the quality of workmanship. Risks of Non-Participation PGE and its customers would miss the opportunity to bring PGE welding staff current with important and new thermal spray coating techniques.	$33,900
Reliability Total	**$740,330**
Total 2016 R&D Projects	**$2,833,490**

Exhibit 605
IT Summary by Operating Area

Funtion	2012 ACTUALS	2013 ACTUALS	2014 ACTUALS	2015 Budget	2016 Budget	2016-2014 Delta	Annual % delta 2015-2014
Production							
Assigned	202,365	23,464	335,623	181,590	475,048	139,425	18.97%
Allocated	6,151,591	5,560,113	6,695,618	7,979,706	8,336,379	1,640,761	11.58%
Total Production	6,353,956	5,583,578	7,031,241	8,161,296	8,811,427	1,780,186	11.95%
						-	
Power Operations						-	
Assigned	686,177	656,210	459,935	513,793	534,388	74,453	7.79%
Allocated	1,826,800	1,786,306	1,610,682	2,084,287	2,172,680	561,997	16.14%
Total Power Ops	2,512,977	2,442,516	2,070,617	2,598,080	2,707,068	636,451	14.34%
						-	
Transmission						-	
Assigned	454,204	348,684	323,714	1,070,994	1,109,256	785,541	85.11%
Allocated	668,580	1,191,467	1,415,835	1,617,120	1,687,096	271,261	9.16%
Total Transmission	1,122,784	1,540,151	1,739,549	2,688,114	2,796,351	1,056,802	26.79%
						-	
Distribution						-	
Assigned	356,867	1,426,905	732,596	1,467,072	2,132,740	1,400,144	70.62%
Allocated	15,168,671	13,760,361	16,563,746	19,488,369	20,331,661	3,767,915	10.79%
Total Distribution	15,525,538	15,187,266	17,296,342	20,955,440	22,464,401	5,168,059	13.96%
						-	
Customer Acctg/Svc						-	
Assigned	3,359,540	1,928,513	2,518,166	1,642,408	1,724,973	(793,193)	-17.23%
Allocated	8,746,898	11,039,483	13,321,027	14,773,250	15,412,511	2,091,484	7.56%
Total Customer Acctg/Svc	12,106,438	12,967,996	15,839,193	16,415,658	17,137,484	1,298,291	4.02%
						-	
A&G						-	
Assigned	7,701,300	7,080,978	6,280,292	4,699,394	4,979,759	(1,300,533)	-10.95%
Allocated	8,065,032	8,571,131	9,774,225	11,579,294	12,078,807	2,304,582	11.17%
Total A&G	15,766,332	15,652,109	16,054,517	16,278,687	17,058,566	1,004,049	3.08%
						-	
Totals						-	
Assigned	12,760,454	11,464,754	10,650,327	9,575,250	10,956,164	305,838	1.43%
Allocated	40,627,572	41,908,861	49,381,133	57,522,025	60,019,133	10,638,000	10.25%
Grand Total	53,388,026	53,373,616	60,031,459	67,097,276	70,975,298	10,943,838	8.73%
2014 IT Deferral (UE 262)			(6,947,200)	1,736,800	1,736,800		
Labor Adjustment					(1,558,435)		
Adjusted Total	53,388,026	53,373,616	53,084,259	68,834,076	71,153,663	18,069,403	15.78%

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Production

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Quennoz
Aaron Rodehorst

February 12, 2015

Table of Contents

I. Introduction

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

A. My name is Stephen Quennoz. My position at PGE is Vice President, Power Supply. I am responsible for all aspects of PGE's power supply generation.

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 support the operations and maintenance (O&M) associated with PGE's long-term power supply resources, both owned plants and contracts. We discuss recent plant performance and PGE's ongoing efforts to improve safety, reliability, and the performance of our generation fleet. We also identify and discuss the major drivers for the 2016 test year O&M expenses relating to thermal, hydro, and renewable operations, including environmental services, licensing, and compliance relating to our generation fleet.

Q. What are PGE's goals for plant operations and maintenance?

A. Our primary goals for plant-related activities are to minimize the volatility of energy costs and 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 the 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 PGE's operation and maintenance practices; our forecast of 2016 test year Generation O&M expenses; and expected operations and maintenance events in 2016. In Section IV, we discuss 2016 generation related environmental services, compliance, and licensing expenses. We present our qualifications in Section V.

II. PGE's Generation Resources

A. Generation Resources

Q. Have you prepared an exhibit that shows all of PGE's power supply resources for the 2016 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 2016 Net Variable Power Cost (NVPC) forecast presented in PGE Exhibit 400.

Q. Have PGE's long-term power supply resources changed significantly since the UE 283 general rate case?

A. Yes. Pursuant to PGE's 2009 Integrated Resource Plan (IRP), the Commission acknowledged Action Plan, and the subsequent request for proposals (RFPs), PGE is adding a new base load energy resource, the Carty Generating Station (Carty). Carty is currently anticipated to come online in the second quarter of 2016. PGE Exhibit 300 discusses the IRP and RFP processes leading to the selection of the bid submitted by Abengoa S.A., the expected performance parameters of Carty, and the revenue requirement associated with Carty.

B. Plant Performance

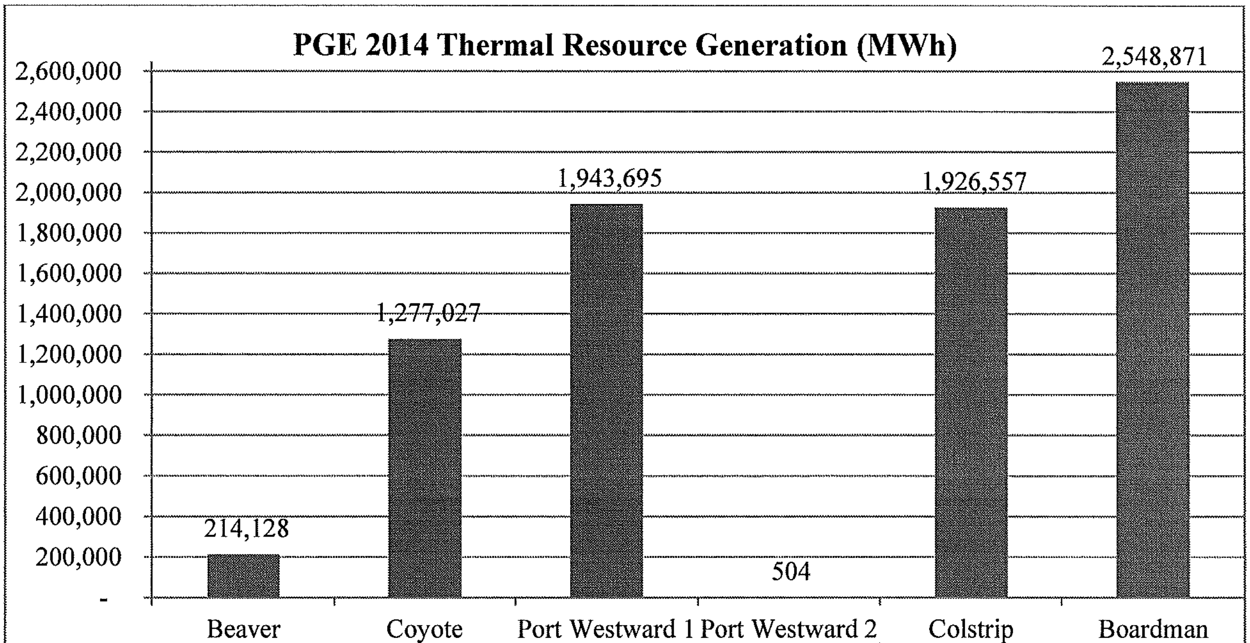
Q. What are PGE's goals for generation plant performance?

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 recently?

A. In 2013, the majority of PGE's plants exceeded the stated goals for performance in terms of efficiency, measured as cost per unit of output, and availability, measured as economic availability factor.[1] Port Westward 1 was recognized for the fourth consecutive year for being ranked in the top-20 for heat rate of a gas-fired resource.[2,3]

In 2014, PGE's thermal plants performed superbly and experienced no major forced outages. Thermal generation in 2014 was slightly lower than historical levels for some of our thermal plants due to a slightly above-normal hydro year, major inspections, and overhaul work at some of the thermal plants.



Source: 2014 EGR&D YTD Report.

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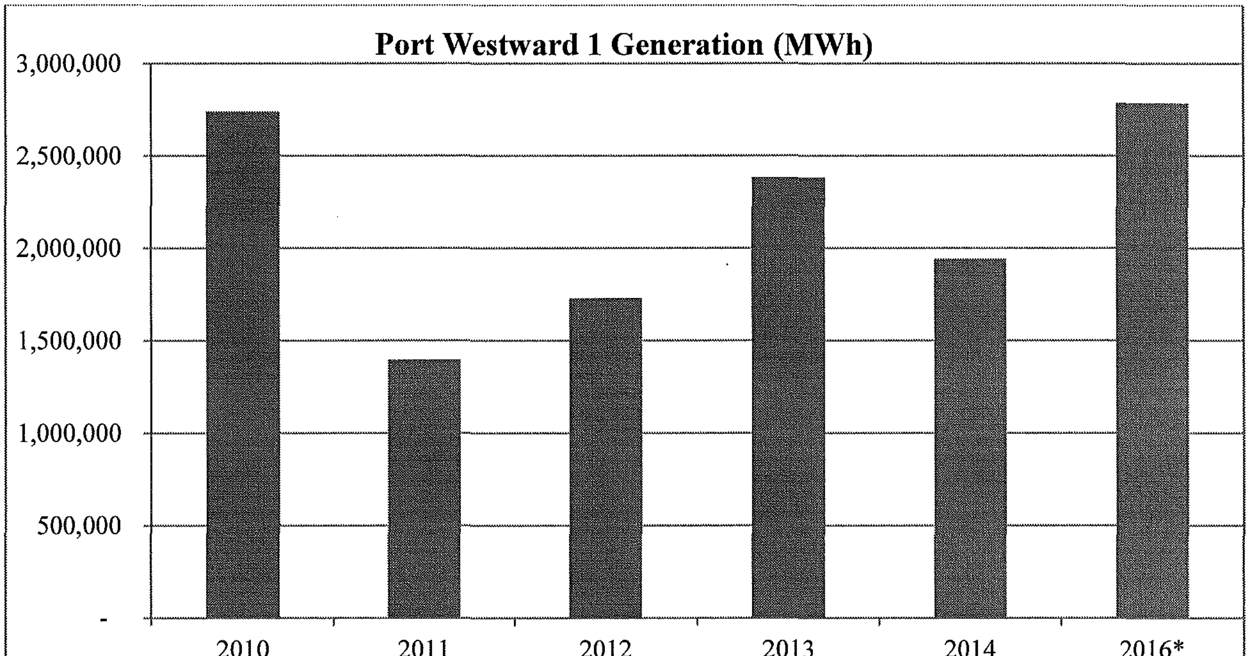
[1] Cost per unit of output is defined as: $\frac{\$O\&M}{MWh}$. Economic availability factor is defined as: $\frac{PH-(POH+MOH+FOH)}{PH}$, where PH is period hours, POH is planned outage hours, MOH is maintenance outage hours, and FOH is forced outage hours.

[2] Heat rate is a measure of a thermal generating plant's efficiency, relating the amount of heat input (BTU) required to generate one unit of energy output (KWh).

[3] As reported by "Electric Light & Power": http://www.elp.com/articles/print/volume-92/issue-6/sections/industry-report/2013-operating-performance.html

Q. How does the dispatch of Port Westward 1 compare to previous years?

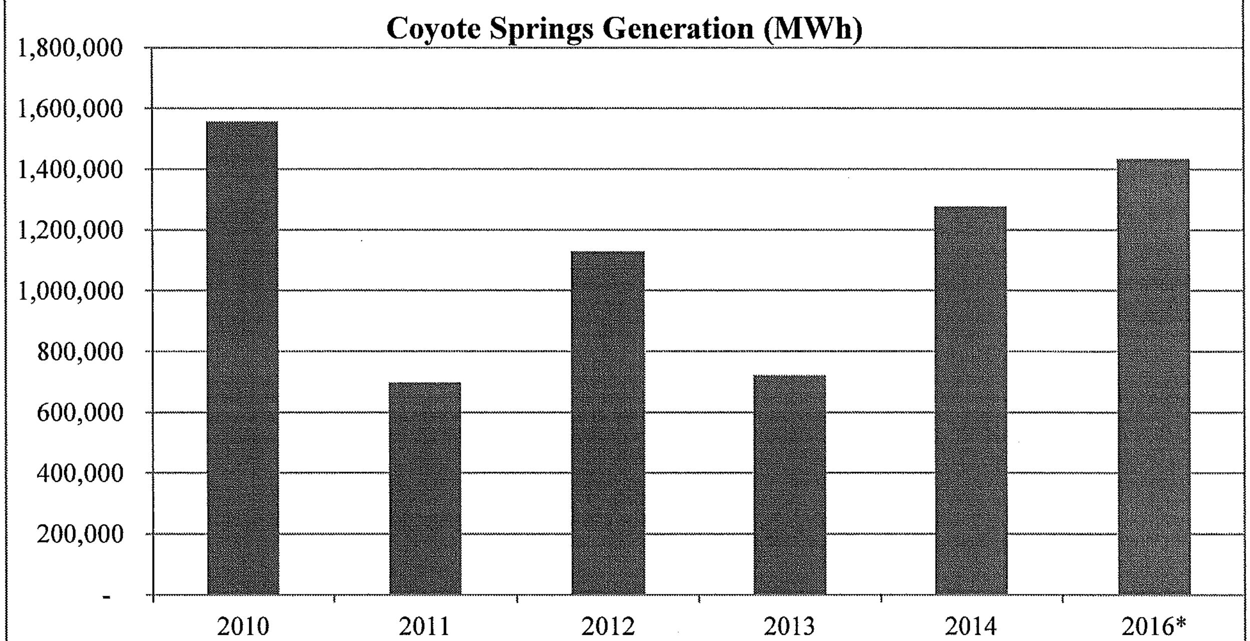
A. The chart below summarizes Port Westward 1 generation. Port Westward 1 generation was lower in 2011 and 2012 due to above-normal hydro conditions, which contributed to lower regional prices and displaced thermal resources. Port Westward 1 generation in 2013 has increased compared to 2011 and 2012 due to more normal hydro conditions and extended outages at Boardman, Colstrip and Coyote Springs. Generation decreased in 2014 compared to 2013 due to a slightly above-normal hydro year and Boardman, Colstrip, and Coyote Springs all returning to service.



*2016 based on initial NVPC forecast presented with this filing.

Q. Does Coyote Springs' dispatch follow the same pattern as Port Westward 1?

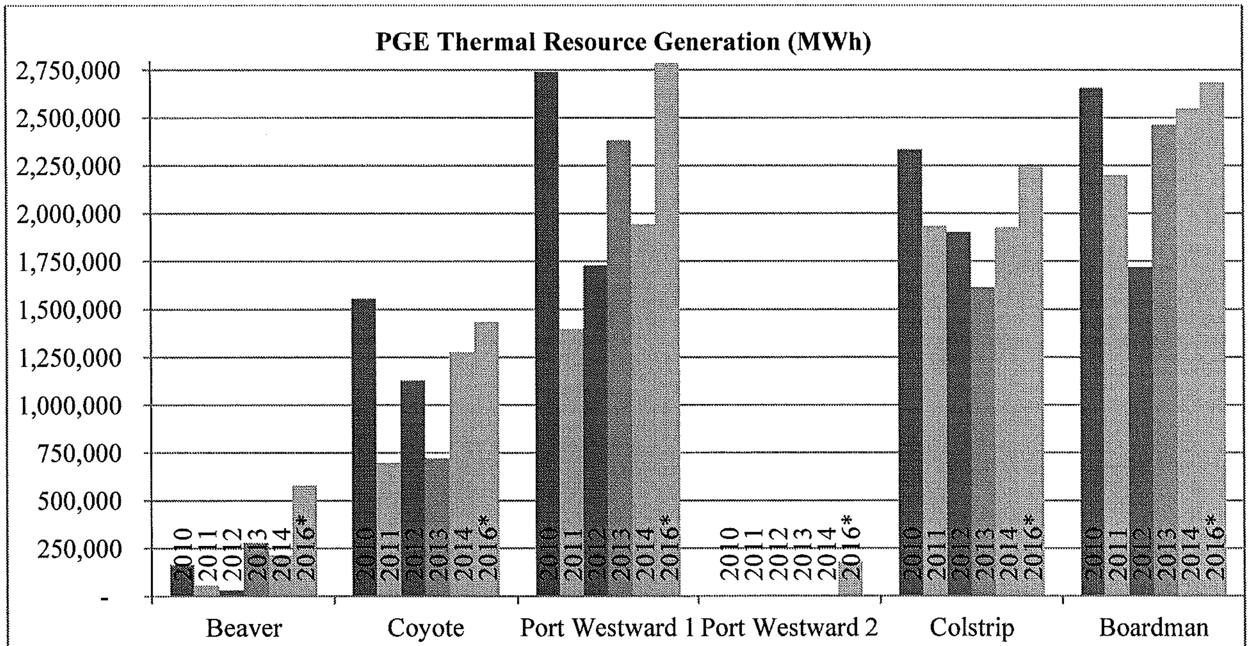
A. Yes. With the exception of 2013, Coyote Springs follows a pattern similar to Port Westward 1. Coyote Springs generation was reduced in 2013 because of the extended outages.



*2016 based on initial NVPC forecast presented with this filing.

Q. How does the 2016 expected generation for PGE's thermal resources compare to previous years?

A. The chart below summarizes actual thermal generation between 2010-2014 and PGE's current 2016 forecast for each of our existing thermal resources. PGE Exhibit 400 presents our 2016 NVPC forecast.



*2016 based on initial NVPC forecast presented with this filing

III. Generation Plant O&M

A. O&M Practices

Q. What is PGE's philosophy regarding O&M practices?

A. We strive for Operational Excellence and Corporate Responsibility as a part of PGE's core business strategy. In Power Supply, we recognize that the safe and reliable operation of our plants is key to our ability to execute our business strategy and provide customers with excellent service. Through our O&M practices we are committed to ongoing efforts to maintain high-levels of availability and reliability to maximize economic dispatch of our plants while simultaneously ensuring the safety of our plant personnel.

1. Safety

Q. How does safety integrate with PGE's O&M practices?

A. Safety is a key component of our core business strategy and our O&M practices. PGE's safety strategy reflects the critical elements in the American National Standard for Occupational Health and Safety Management Systems, specifically management leadership, employee engagement, planning, implementation, evaluation, and corrective action.[4] In 2014, PGE reorganized the Corporate Safety group and created a Generation Safety team. In doing so, the Generation Safety team is positioned to apply a strategic approach for high quality, consistent safety performance. The team functions as an embedded team of four safety professionals who are closely tied to plant operations teams.

Q. What are PGE's goals for generation safety?

A. The Generation Safety team targets:

[4] American National Standards Institute (ANSI) /American Industrial Hygiene Association (AIHA) Z10-2012.

- Progression by Coyote Springs from Merit to Star status within the Occupational Safety and Health Administration (OSHA) Voluntary Protection Programs (VPP);
- Continued improvement of PGE's soft-tissue injury reduction program;
- Implementation of standardized behavior-based safety observation programs at each generating facility;
- Use of a consistent pre-job briefing process for "tail board" meetings;
- Continued improvement of the safety management system using PGE's mySafety platform; and,
- Implementation of multiple leading indicators for ongoing tracking of safety performance.

On a long-term basis, the Generation Safety team targets zero-level injury rates.

Q. What are the OSHA Voluntary Protection Programs?

A. The OSHA VPP recognize employers and workers who implement effective safety and health management systems and maintain injury and illness rates below national Bureau of Labor Statistics averages for their industry.[5]

Q. Please explain behavior-based safety observation programs.

A. Behavior-based safety observation programs consist of training and encouraging employees to effectively implement safety improvements in their workplace through peer-to-peer and management observation, evaluation, and coaching.

Q. What progress has PGE made toward achieving these safety goals?

A. All of our thermal and hydro facilities have been recognized for achieving participation status in the Oregon-OSHA Safety and Health Achievement Recognition Program

[5] https://www.osha.gov/dcsp/vpp/all_about_vpp.html

(SHARP). Biglow Canyon Wind Farm's (Biglow) SHARP status is currently pending and is expected to be awarded in early 2015. In 2011, Coyote Springs achieved VPP Merit status, the first level of participation within OSHA VPP. Coyote Springs is positioned to achieve Star status during 2016.

Q. What safety initiatives does PGE have planned for 2016 and beyond?

A. Using our mySafety software platform, PGE's Generation Safety team will continue to integrate software-based tools into our generation business processes. Our emphasis in 2016 will be on incident reporting follow-up, job safety analysis, behavior-based safety observations, and leading indicators. All generation managers and supervisors are expected to take a safety leadership training course over a two-year period, concluding in 2016. Additionally, PGE is targeting OSHA VPP Merit or Star status at each generation facility by 2018.

2. Reliability

Q. How is PGE managing its O&M practices with regard to reliability and availability?

A. Our Generation Reliability and Maintenance Excellence (RME) program improves our maintenance practices that directly impact the operation of our generation resources. Additionally, as part of the Dynamic Dispatch Program (DDP), the Power Supply Engineering Services (PSES) department engaged in generation plant cycling studies to better define the capabilities and operating parameters of some of PGE's generation resources.

Q. Please summarize the RME effort.

A. RME is PGE's comprehensive equipment management program that supports plant safety and availability. PGE uses RME to operate and maintain plant equipment to achieve the lowest overall life cycle cost. While RME is an ongoing, continuously evolving program for PGE, we aim to achieve a sustained long-term top quartile availability factor at each plant with optimized maintenance costs. To achieve our generation operations goals, we are implementing metrics, standards, and tools that include:

- Modeling plants with Reliability Block Diagramming software;
- Ranking assets by importance to inform the management plan for assets;
- Continuously optimizing maintenance through Reliability Centered Maintenance evaluations;
- Using condition-based monitoring tools and programs to reduce the amount and impact of corrective maintenance;
- Training and adhering to fleet-wide work standards; and
- Targeting practices to include approximately 80 percent proactive maintenance and 20 percent corrective maintenance.

Q. When does PGE anticipate achieving these expected results?

A. The current goal for achieving these expected results is year-end 2017. However, RME is a sustained strategy and will be an ongoing, evolving program that continues to improve PGE's maintenance practices.

Q. How do these efforts benefit customers?

A. RME produces asset-related and personnel-related benefits for PGE and our customers. The primary asset-related benefits are:

- Increased plant availability and reliability;
- Optimization of maintenance practices and equipment replacement; and,
- Installation of new equipment with the lowest lifecycle cost.

The asset-related benefits result in lower NVPC for our customers and higher levels of reliability to serve customer load.

The primary personnel-related benefits are:

- Improved safety;
- Workforce efficiency and effectiveness; and,
- Knowledge transfer.

The personnel-related benefits result in better use of our existing staff, more efficient maintenance procedures, more effective information sharing, and allow new plant staff to more quickly learn plant maintenance procedures. All of these benefits contribute to more efficient and effective operation and maintenance of our generation assets.

Q. Does PGE plan to expand on any of these efforts in 2016?

A. Yes. PGE plans to create a centralized onsite monitoring and diagnostic (M&D) center beginning in 2016. The objective of the M&D center is to create a centralized and integrated fleet-wide monitoring center that will improve PGE's ability to detect and correct equipment and performance problems at our plants. Additionally, the data available from the M&D center will allow greater visibility of plant asset conditions, which directly support our RME program's focus on maintenance efforts to reduce the risk of equipment failure and to reduce the economic impact of any plant outage.

Q. Has PGE benchmarked peer utilities' monitoring and maintenance programs?

A. Yes. PGE's reliability centered maintenance, technician training, employee performance, and safety programs were in-line with or slightly more mature than peer utilities. However, peer utilities had more developed fleet-wide monitoring programs than PGE.

Q. How does PGE currently monitor its assets?

A. PGE uses a third-party vendor to perform fleet-wide monitoring, which has proven effective at reducing operation costs through improved detection of equipment problems. However, the current monitoring program has limitations regarding the depth of monitoring and the lack of real-time thermal performance analysis. Additionally, the outside vendor is not fully integrated into PGE's culture and process, decreasing our effectiveness at correcting equipment problems detected through monitoring.

Q. How will the improved monitoring from the M&D center benefit customers?

A. The M&D center will align maintenance to the condition of plant assets, increase early detection of component failures, standardize monitoring across PGE's fleet, and reduce labor used for periodic inspections. The M&D center will directly benefit customers through improved generation reliability and availability, which will allow PGE to maximize economic dispatch of our generation assets and reduce replacement power costs due to unexpected outages. Improved fleet monitoring also creates alignment between the monitoring program and condition-based maintenance, which result in reduced labor used for periodic inspections and maintenance.

Q. Please summarize the plant cost of cycling studies.

A. We recently completed cost of cycling studies for PGE's thermal generation fleet and the Pelton and Round Butte (PRB) hydroelectric plants. The purpose of these studies is to develop and analyze the cost associated with cycling each unit, based on historical operating and cost information. With these studies, we are able to estimate future costs associated with increased cycling due to market and regulatory changes, such as 15-minute scheduling.

To complete these studies, PGE contracted with a third-party firm that has over two decades of experience and has completed over 400 cycling cost analyses.

Q. What is plant cycling?

A. Cycling is the frequent movement of output (i.e., increasing or decreasing of generation) produced by a plant. This includes on and off cycling (i.e., plant start-ups and shut downs) and load following. For traditionally base load thermal plants, load following is movement greater than 20 to 50 percent of the unit's gross dependable capacity.

Q. How does PGE plan to use the information from the plant cost of cycling studies?

A. The studies will provide valuable operating information to our Power Operations group, PSES, and plant operators. PGE plans to use the results from the cost of cycling studies as a wear and tear component cost for economic dispatch of the plants, particularly in the Real Time Dispatch Tool (RTDT) being developed for portfolio optimization under the DDP. Additionally, the studies provide information regarding specific plant operating constraints that can be incorporated in the MONET model. PGE Exhibit 400 discusses updates to the ancillary service assumptions in MONET based on the results of the cost of cycling studies.

B. Plant O&M

Q. What are the changes in PGE's plant O&M between 2014 and 2016?

A. Table 1 below summarizes the changes in total Plant O&M expenses. These amounts include adjustments for emissions control chemical costs and the various major maintenance accruals.

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

Operating Area	2014 Actuals	2016 Test Year	Delta	Annual % Change
Coal-fired Plants	$48.0	$48.4	$0.5	0.5%
Gas-fired Plants	$27.8	$30.3	$2.4	4.3%
Hydro Plants	$11.7	$10.7	($1.0)	(4.4%)
Wind Plants	$16.7	$20.9	$4.2	11.7%
General & Miscellaneous	$15.2	$16.5	$1.2	4.0%
Sub-Total	**$119.4**	**$126.7**	**$7.3**	**3.0%**
Environmental	$4.8	$7.5	$2.7	25.3%
Information Technology (IT)	$7.9	$11.8	$4.0	22.8%
Total	**$132.0**	**$146.0**	**$14.0**	**5.2%**

**Amounts exclude Carty and Trojan Entities. Boardman reported at 80% share in 2014.*
^May not sum due to rounding.

Q. **What are the changes in non-labor plant O&M expenses?**

A. The changes in non-labor plant O&M expenses from 2014 to 2016 are summarized in Table 2 below. PGE labor-related expenses are discussed in PGE Exhibit 500.

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

Operating Area	Delta	Annual % Change
Coal-fired Plants	($2.4)	(3.2%)
Gas-fired Plants	$1.4	3.7%
Hydro Plants	($1.8)	(16.7%)
Wind Plants	$3.6	10.5%
General & Miscellaneous	$1.0	7.9%
Sub-Total	**$1.8**	**1.1%**
Environmental	$2.3	33.7%
IT Expenses	$2.9	27.4%
Total	**$7.0**	**3.7%**

**Amounts exclude Carty and Trojan Entities. Boardman reported at 80% share in 2014.*
^May not sum due to rounding.

Q. **What are the main drivers for the changes in non-labor plant O&M expenses?**

A. The main drivers for the change in generation non-labor O&M expenses are O&M for Port Westward Unit 2 (PW2) and the Tucannon River Wind Farm (Tucannon), reduced maintenance work at Boardman compared to 2014 and 2015, reduced non-labor O&M due to an increase in maintenance work on PGE's aging hydro fleet and completion of certain projects in 2014, and increased environmental non-labor O&M due to increasing hydro licensing requirements. We discuss department and plant specific increases in their respective sections below.

Q. Are there any major efficiencies that help offset the increase in non-labor O&M?

A. Yes. The Service and Maintenance Agreement (SMA) and Guaranteed Availability and Warranty Extension (GAWE) agreement that cover maintenance and repair work at Phases II and III of Biglow will expire by the end of 2015. We are working to execute a different maintenance and repair agreement structure that results in reduced O&M expenses compared to the existing agreements.

Q. What are the SMA and GAWE?

A. The SMA for Phases II and III of Biglow is similar to a long-term service agreement (LTSA) at a thermal plant. It covers regular, scheduled maintenance on the wind turbines. The GAWE is an extension of the manufacturer's warranty and covers the cost of materials and labor for any non-scheduled repair work needed to the entire turbine, including the gearbox, blades, generator, and main shaft bearing.

Q. What is the 2014 expense associated with the SMA and GAWE?

A. The 2014 expense for the SMA and GAWE for Phases II and III is approximately $10.8 million.

Q. What alternative agreement structure is PGE considering for 2016?

A. PGE is considering a three part maintenance and repair strategy that consists of:

- Third-party scheduled services plus time and materials (ST&M) agreement for non-scheduled maintenance;

- Annual O&M budgeted for parts; and,
- A wind-specific capital fitness fund.

The ST&M agreement will cover scheduled services, inspections, troubleshooting, and time and materials on specified repairs. PGE will assume the risk and be responsible for purchasing replacement parts and major equipment (e.g., gearbox, main bearing, etc.) as well as the labor associated with major equipment replacement.

Q. Did PGE solicit a quote for agreements similar to the current SMA and GAWE?

A. Yes. We solicited a quote for new agreements that are the same as the current agreements covering Phases II and III. Assuming we executed agreements that are the same as the current SMA and GAWE, the estimated 2016 expense is higher than the current 2014 expense.

Q. What are the anticipated savings from the alternative ST&M agreement structure?

A. The estimated savings are approximately $4.5 million in O&M for Biglow. The 2016 test year Biglow O&M budget includes approximately $6.4 million for the ST&M agreement and the smaller replacement parts (e.g., pumps, belts, etc.) for which PGE will assume responsibility. PGE intends to establish a wind fitness capital fund for 2016. However, because PGE's rate base in this proceeding is based on year-end 2015, we have not included the wind fitness fund in our test year rate base estimate.

C. Full Time Equivalent Employees

Q. What is the change in Full Time Equivalent employees from 2014 to 2016?

A. The increase in Full Time Equivalent employees (FTEs) is 41.

Q. What are the major drivers for the increase in generation related FTEs?

A. The main drivers for the increase in generation-related FTEs between 2014 and 2016 are:

- Ten FTE's resulting from the acquisition of a 10 percent share in Boardman from Power Resources Cooperative (PRC) approved in Order No. 14-422;
- Completion of hiring of the three FTEs for PW2 and five FTEs for Tucannon; and
- Additional PSES positions being added in 2015 and 2016 to support increasing regulatory requirements, plant support needs, asset growth, and the M&D center.

We discuss the changes in plant specific FTEs in their respective O&M sections below.

Q. Please explain the position additions in Power Supply Engineering Services.

A. PSES provides civil, electrical, and mechanical engineering 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, continually expanding regulatory and reporting requirements, and aging generation resources, PSES requires additional administrative and engineering positions.

Q. What new PSES positions are being added?

A. PSES is adding a total of seven new FTEs for engineering support and administrative support. PSES is adding the following engineering support positions:

- One FTE in 2015 for an electrical engineer to support engineering at the thermal plants.
- One FTE in 2016 for a cyber-security engineer. This new engineer will work with existing PSES staff to implement North American Electric Reliability Corporation's (NERC) Critical Infrastructure Protection (CIP) and other cyber security requirements for PGE's control systems. Also, the addition of new assets increases the number of systems and cyber security requirements.

- One FTE in 2016 for a mechanical engineer to support engineering at the plants including enhanced maintenance at Beaver.
- Two FTEs in 2016 to support and staff the M&D center. The M&D engineers will be responsible for monitoring plant performance and analyzing the data received from each of the plants. The expense for these positions is partially offset by a reduction to contracted third-party monitoring services.

PSES is adding the following administrative support positions:

- One FTE in 2015 for an electrical designer. This position will support increased compliance obligations due to NERC and CIP requirements. Additionally, the electrical designer position is needed to supplement existing personnel due to the increased work as a result of assets being added.
- One FTE in 2016 for an administrative position responsible for drawing control and records coordination. PSES is responsible for control, indexing, and storage of approximately 100,000 drawings and records. As more systems and assets are added, additional support is needed to maintain and update drawings and records.

Q. Please explain the other non-plant specific FTE additions.

A. The FTEs being added in other departments are:

- One FTE in 2016 for a forecaster/meteorologist in the Real Time Operations department. This position will be responsible for near-term (e.g., hour-ahead, day-ahead, week-ahead) wind and load forecasting and the creation and operation of more detailed, enhanced, and optimal near-term forecasting tools.

- One FTE in 2016 in the Dispatchable Standby Generation (DSG) department for a project manager. This FTE is a cross training position that is transferred from IT for 2016. The FTE impact is a net zero change company-wide.
- Two FTEs in 2015 in the Generation Safety department. The Generation Safety department was established in June 2014 and consists of four staff that were transferred from the Corporate Safety department. The FTE impact is a net zero change company-wide. Because of the timing of the creation of the Generation Safety department, this results in two FTE in 2014 and four FTEs in 2015.

Q. Did PGE make adjustments to the 2016 test year FTE count to account for expected unfilled positions?

A. Yes. PGE adjusts the 2016 test year FTE count to reflected expected vacancies (i.e., positions that will not be filled for the entire 2016 test year). For PGE's generation related departments, the unfilled positions adjustment results in a reduction of 13 FTEs in the 2016 test year. The process for budgeting and adjusting FTEs is discussed in detail in PGE Exhibit 500.

D. Thermal Operations and Maintenance

1. Coal

Q. What are the major drivers of the change in coal non-labor O&M expenses?

A. The major drivers for the change in coal non-labor O&M expenses are:

- An increase due to PGE's acquisition of PRC's 10% share of Boardman; and,
- A decrease due to reduced maintenance at Boardman compared to 2014 and 2015.

Q. Please discuss the acquisition of PRC's share of Boardman.

A. PGE acquired PRC's 10% share of Boardman on December 31, 2014, as approved by Commission Order No. 14-422. As part of this acquisition, PGE was assigned a Power Purchase Agreement (PPA) between PRC and Turlock Irrigation District (TID). PGE assumed responsibility for the O&M associated with the 10% share; however, revenues from the TID PPA offset the increase in O&M. The revenues from the TID PPA are included in PGE's NVPC forecast as a reduction to NVPC.

Q. Please explain the decrease in maintenance expenses at Boardman.

A. Boardman conducted a high pressure/intermediate pressure steam turbine inspection in 2014 and a low pressure steam turbine inspection in 2015, which resulted in increased maintenance expenses. There are no planned major maintenance activities at Boardman in 2016, which results in decreased maintenance expenses in 2016 compared to 2014.

Q. What is the change in FTEs related to coal plant operations?

A. There is an increase of approximately 12 FTEs at Boardman. Ten of these FTEs are the result of the increase in PGE's ownership share of Boardman due to the PRC Agreement. The remaining two FTEs are positions that were recently filled in the fourth quarter of 2014, but appear as an increase when comparing 2016 to 2014.

Q. Does PGE have any major maintenance activities planned for coal plants in 2016?

A. Yes. The Colstrip Unit 3 and Unit 4 generating facilities are on three-year maintenance outage cycle schedules as specified in the Colstrip business plan. Unit 4 is scheduled for a maintenance outage in 2016 and Unit 3 is scheduled for a maintenance outage in 2017. However, Colstrip O&M is slightly declining from 2014 to 2016 because 2014 was also a maintenance outage year and repair work to the Unit 4 generator was completed in 2014.

Q. Is the Colstrip maintenance outage accounted for in PGE's 2016 NVPC forecast developed in MONET?

A. Yes. Whether in a general rate case or annual update tariff proceeding, PGE's NVPC forecast reflects the power cost effect of planned maintenance outages expected to occur at PGE's plants during the test year. Planned maintenance outages are typically scheduled to occur during periods when a plant is expected to be economically displaced in order to minimize the effect on power costs.

Q. Please provide an update on the Boardman biomass project.

A. In our November 5th update filing in the 2014 NVPC proceeding, the 100 percent biomass test burn was rescheduled to occur in 2015 and was removed from PGE's 2014 NVPC forecast. In the 2015 NVPC proceeding, the NVPC forecast was updated to reflect the co-fire test being rescheduled from 2014 to 2015. Consistent with the stipulation reached in Docket No. UE 266, PGE included the refund for the 2014 co-fire test burn net cost, with interest at PGE's weighted average cost of capital, in our 2015 NVPC forecast and updated the forecast to include the rescheduled co-fire test.

Q. What is the current status of the torrefier plant and testing?

A. Mechanical and electrical installation of the torrefier plant is complete. We continue to work on commissioning and testing of the torrefier plant and are continuing to accept deliveries of green biomass fuel sources. Our current projected schedule targets co-firing and the 100 percent test burn to occur in 2015. However, the schedule is subject to change due to the research and development nature of this project. PGE will continue to monitor the progress of the Boardman biomass project and notify parties accordingly.

2. Gas

Q. What are the major drivers of the change in gas non-labor O&M expenses?

A. The $1.4 million increase in gas non-labor O&M expenses is driven primarily by approximately $1.3 million in non-labor O&M due to the addition of PW2. Other increases in gas non-labor O&M are offset by the reduction of the Coyote Springs major maintenance accrual for 2016.

Q. Why is PGE proposing a reduction to the Coyote Springs major maintenance accrual?

A. LTSA expenses for Coyote Springs consist of a variable and a fixed fee. The variable fee is defined as the product of the variable price specified in the LTSA and factored hours, which are based on operating hours of the unit. LTSA expenses were below normal for 2013 due to reduced operating hours resulting from the unanticipated outages at Coyote Springs. As a result of the reduced operating hours and below normal LTSA expenses for 2013, the major maintenance accrual resulted in a larger than normal balance during 2013. PGE is proposing to reduce the major maintenance accrual to re-align the accrual with anticipated LTSA and major maintenance work going forward.

Q. What is the FTE increase related to gas plant operations?

A. There is an increase of ten FTEs for gas plant operations: six at Beaver, two at Coyote, one at Port Westward, and one at PW2.

Q. Please describe the FTE increases at Beaver, Coyote, and Port Westward.

A. The increase of FTEs at Beaver includes three generation technicians and three temporary union positions. The generation technicians are part of an on-going effort to supplement the workforce at Beaver. Similar to Coyote, these positions will reduce overtime at Beaver and are partially offset by the savings from this reduction. Although the three temporary union positions appear to be an increase, this is because PGE opted to contract out the work these positions would have done in 2014. As such, 2014 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 2016.

The new FTEs at Coyote are a warehouse/storeroom position in 2015 and a union technician in 2016. The warehouse/storeroom position will be responsible for checking in materials, stocking, performing fulfillments and returns, cycle counts, and requesting new materials. Currently, the administrative positions at Coyote Springs are sharing the warehouse/storeroom workload. This has created a backlog and increased duties have caused the work load to exceed the capabilities of the current plant personnel. The union technician is needed to supplement the existing technician staff. Increasing generation initiatives and maintenance work is causing an increase in overtime worked by existing staff. The additional union technician will reduce overtime and is partially offset by the savings from this reduction.

Port Westward is adding a project manager in 2015 for operations, maintenance, and engineering support. The position is intended to support succession planning in anticipation of the retirement of multiple senior technical leaders at the plant. Due to training time and knowledge transfer from existing staff, this position is needed to work concurrently with the existing senior technical leaders prior to their retirement.

E. Hydro Operations and Maintenance

Q. What are the major drivers of the change in hydro non-labor O&M expenses?

A. The decrease in non-labor hydro O&M is primarily the result of increased maintenance work done in 2014 due to the age of our hydro fleet. The average age of our hydro facilities is approximately 77 years. As our hydro generating facilities age, they require increased maintenance and capital additions to maintain safe and reliable operation. In 2014, PGE was able to allocate budgets accordingly and complete an increased amount of the needed maintenance work. Additionally, certain project work was completed in 2014.

Q. What new FTEs related to hydro plant operations are being added?

A. There are two new FTEs supporting hydro plant operations: a maintenance specialist at PRB beginning in 2015 and a Journeyman Electrical Machinist at the West Side Hydro Projects in 2016.

The maintenance specialist at PRB was created as part of the contract with the Confederated Tribes of Warm Springs. The position will be responsible for plant records administration, administrative support, inventory support, and compliance support.

Due to the increased asset additions, such as the North Fork surface collector, to the various West Side Hydro facilities, additional support is needed to perform mechanical maintenance. The Journeyman Electrical Machinist will be responsible for mechanical maintenance of equipment at the generating plants and fish facilities located on the Clackamas River.

F. Wind Operations and Maintenance

Q. What are the major drivers of the change in wind non-labor O&M expenses?

A. The major drivers of the change in wind non-labor O&M expenses are the addition of Tucannon in 2015 and the reduction in Biglow non-labor O&M due to the new maintenance agreements for Biglow Phases II and III. The reduction in Biglow non-labor O&M is discussed in Section III.B.

Q. What is the budgeted 2016 non-labor O&M expense for Tucannon?

A. The 2016 non-labor O&M for Tucannon, excluding IT and environmental related O&M, is approximately $7.0 million.

Q. Please explain the four additional FTEs related to wind plant operations.

A. One FTE is being added in 2015 for a Project Performance Analyst. The Project Performance Analyst will be responsible for monitoring performance of the 233 turbines at PGE's wind plants, compiling performance reports, and investigating low producing turbines. This will allow PGE to more quickly detect issues with our wind fleet and implement corrective actions in a timely manner. Additionally, this position will supplement the new maintenance and repair strategy at Biglow Phases II and III.

The remaining three FTE additions for wind plant operations are the personnel required to support commercial operation of Tucannon.

IV. Environmental and Licensing Services

Q. Why do you discuss Environmental and Licensing Services here in the Generation testimony?

A. Environmental and Licensing Services (ELS) reports to PGE's Senior Vice President, Power Supply and Operations and Resource Strategy, and provides general support to all of PGE's facilities, in particular generation facilities. ELS is responsible for required compliance and other regulatory activities including monitoring wildlife, fishery operations, FERC hydro license requirements, air quality, and waste management. PGE Exhibit 600 discusses the A&G expenses associated with ELS.

Q. What is PGE's budget for ELS in 2016?

A. PGE forecasts generation related ELS expenses to be $5.2 million in 2016. Table 3 below provides a summary of non-labor generation O&M for ELS by function.

Table 3
Generation Related ELS Non-Labor Budget
($millions)*^

	2014 Actuals	2016 Test Year	Delta
West Side Hydro	$0.9	$2.1	$1.2
Pelton-Round Butte	$1.8	$2.5	$0.8
Generation Support/Other	$0.3	$0.6	$0.4
Total	**$2.9**	**$5.2**	**$2.3**

**Amounts exclude Carty and Trojan Entities. Boardman reported at 80% share in 2014.*
^May not sum due to rounding

Q. What are the primary causes for the increase in PGE's ELS budget?

A. The increases in ELS O&M expenses are primarily due to increasing compliance activities specified in the FERC licenses for our West Side Hydro and PRB hydro projects. The increase is also driven by increased hatchery costs at our hydro projects and environmental compliance costs related to Tucannon.

Q. Please describe the major FERC license work at the West Side Hydro Projects.

A. The new FERC license requires PGE to commence placement of gravel along the Clackamas River below the River Mill facility in 2016. This represents an increase of approximately $0.49 million in O&M for 2016. The gravel will mitigate the impact of the PGE's three main-stem dams which block the migration of alluvial material. O&M expenses for the project will include the excavation, hauling, placement of the gravel along the river, and monitoring of the effects of the augmentation required by our permits and the FERC license. PGE Exhibit 702 provides the FERC license article related to gravel augmentation and PGE's study plan.

Q. Please describe the major FERC license work at the Pelton-Round Butte Project.

A. The FERC license test and verification study requires the implementation of an Acoustic Doppler Current Profile (ADCP) study in Lake Billy Chinook. PGE has delayed the study until now so that it would be timed to fit more strategically with other related studies. There is significant risk that the Fish Committee and fish management agencies could make the case that the project is out of compliance with license study requirements if the ADCP study is not conducted in 2016. The ADCP study is estimated to cost approximately $0.50 million, but is partially offset by a reduction in the Water Quality Program expenses in 2016. PGE Exhibit 703 provides the ADCP study plan.

Q. What is the cause of the additional hatchery expenses in 2016?

A. The $0.11 million in additional hatchery expenses at the Round Butte Hatchery is due to escalating operating costs of the Oregon Department of Fish and Wildlife (ODFW) and additional expenses for the production of incremental Chinook salmon and steelhead smolts for release upstream as part of the anadromous fish reintroduction effort. Also, License

Articles 401(d) and 419 require the Licensees to fund an ODFW mitigation coordinator and fish health management program at PRB, both of which continue to experience annual expense increases. PGE Exhibit 703 provides the FERC license article regarding hatchery funding and PGE's hatchery agreement.

The new FERC license for the Clackamas River hydro facilities requires PGE to fund an ODFW study of hatchery impacts on wild salmon. The effort has been on-going since 2013, but will increase in 2016 to produce the final summary and recommendations report, which will outline future changes in hatchery operations. The increased study efforts represent an approximately $0.10 million incremental O&M expense in 2016. PGE Exhibit 702 provides the FERC license article regarding hatchery funding.

Q. What are the ELS expenses related to Tucannon?

A. The ELS expenses for Tucannon consist of approximately $0.30 million for an avian and bat fatality monitoring study required by the Columbia County (Washington) conditional use permit for Tucannon, and the development and implementation of an eagle conservation plan associated with the authorization of a federal eagle take permit for Tucannon.

Q. Are there any FTE changes in ELS from 2014 to 2016?

A. Yes. There are two new FTEs within ELS: a technician and a specialist.

- The technician position added in 2016 will support regulatory compliance, FERC license implementation and requirements, and environmental projects at PGE's hydro facilities, specifically the Clackamas River hydro facilities. The implementation of additional recreation and land use sites and the associated compliance measures required by the Clackamas license will create an increased and ongoing workload.

- A Specialist will be added in 2015 to support the increased workload regarding regulatory compliance, permit implementation, monitoring, reporting, and project support at PGE's thermal facilities. Our new thermal resources, PW2 and Carty, along with our existing thermal resources, require oversight regarding air permit compliance, acid rain reporting, continuous emissions monitoring, water quality compliance, and various other monitoring and reporting requirements.

V. Qualifications

Q. Mr. Quennoz, please describe your qualifications.

A. I hold a Bachelor of Science degree in Applied Science from the U.S. Naval Academy, and hold Masters Degrees in Operations Analysis from the University of Arkansas, Mechanical Engineering from the University of Connecticut, Nuclear Engineering from North Carolina State University, and an MBA from the University of Toledo. Prior to working for PGE, I held positions as Plant Superintendent at the Davis-Besse Nuclear Station for Toledo Edison and General Manager at the Arkansas Nuclear One Station for Arkansas Power and Light. I also coordinated restart of the Turkey Point Nuclear Station for Florida Power and Light. I joined PGE in 1991 and served as Trojan Plant General Manager and Site Executive. I assumed responsibilities for thermal operations in 1994 and hydro operations in 2000. I was appointed Vice President, Nuclear and Thermal Operations in 1998, and Vice President Generation in 2000. I've held my current position of Vice President, Power Supply since August 2004. My responsibilities include overseeing all aspects of PGE's power supply, as well as the decommissioning of the Trojan nuclear plant. I am a registered Professional Engineer (P.E.) in the State of Ohio.

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
701C	PGE Generating Resource Summary
702	Clackamas River Hatchery Funding and Gravel Augmentation
703	Pelton-Round Butte ADCP Study and Hatchery Funding

Exhibit 701C

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assessing whether the USDA-FS is adequately implementing the annual work plan pursuant to the preceding paragraph, and recommending whether the Licensee should assume such responsibilities directly. The report shall provide that if the Licensee assumes these responsibilities, funding provided to the USDA-FS under the preceding paragraph will be terminated. Upon Commission approval of the report, the Licensee shall, if appropriate, assume responsibility for implementing the annual work plan.

(c) ***Biological Monitoring***

Within 12 months of license issuance, the Licensee shall, after consultation with the Fish Committee and with the approval of the Fish Agencies and the USDA-FS, file with the Commission for approval a biological monitoring plan for the Lower Oak Grove Fork below Lake Harriet Dam. The plan shall have components for evaluating the potential for dewatering steelhead redds, sampling outmigrating juvenile salmonids for ten years, and evaluating the use of the lower Oak Grove Fork by spring Chinook, and shall be consistent with the requirements described in Section VIII.B.3 of the Fish Passage and Protection Plan. Upon Commission approval, the Licensee shall implement the plan.

Article 45. Hatchery Funding

(a) ***Hatchery Agreement*:** Within 12 months of license issuance, the Licensee shall enter into with Oregon Department of Fish and Wildlife (ODFW) and file with the Commission, for approval, an agreement that provides for partial funding of the operation of the ODFW Clackamas River Hatchery and for funding of specified studies and improvements to the Hatchery. Prior to approval of the agreement, the Licensee shall provide ODFW with funding as set forth in paragraph (b)(i) for the marking of Clackamas River Hatchery fish and for the production of spring Chinook at the Clackamas River Hatchery.

(b) The hatchery agreement shall be consistent with the term sheet attached as Exhibit K to the Settlement Agreement, and shall include the following components:

(i) Hatchery Production: Starting the calendar year upon license issuance, the Licensee shall provide ODFW $100,000/year for five years, including any funds provided to ODFW during negotiation of the hatchery agreement, and $50,000/year for the next five years for the marking of Clackamas River Hatchery fish and for the production of spring Chinook at the Clackamas River Hatchery. This obligation shall cease in 2009 if ODFW has not terminated the summer releases of spring Chinook into the Clackamas River. The Licensee's funding obligation shall not exceed a total of $750,000 for these purposes, including any funds provided during negotiation of the hatchery agreement.

(ii) Hatchery Monitoring: Within 12 months of license issuance the Licensee shall, in cooperation with ODFW and after consultation with the Fish Committee, develop an annual monitoring plan, consistent with the requirements of Exhibit K to the Settlement Agreement, to assess the impacts that hatchery-produced anadromous salmonids are having on wild anadromous salmonids in the Clackamas River.

(iii)Hatchery Improvements: By year 11 of the license, the Licensee shall develop, in cooperation with ODFW and after consultation with the Fish Committee, a plan, consistent with the requirements of Exhibit K to the Settlement Agreement, to implement improvement measures, excluding increased hatchery production, to reduce the impacts that hatchery-produced anadromous salmonids are having on wild anadromous salmonids in the Clackamas River.

(c) ***Reporting:*** The Licensee shall provide the following reports to the Commission and the Fish Committee:

(i) The Licensee shall file with the Commission, a copy of ODFW's annual report documenting spring Chinook production at the Clackamas River Hatchery during funding by the Licensee for marking and production as described in paragraph (b)(i). The Licensee may contract with ODFW to prepare this report, which shall include sufficient accounting detail to demonstrate that ODFW use the funding provided by the Licensee for marking Clackamas River hatchery fish and spawning and rearing Spring Chinook at the hatchery.

(ii) Simultaneously with its distribution to the Fish Committee, the Licensee shall provide the Commission a copy of the annual report on monitoring efforts.

(iii)Not later than April 1 of each year, the Licensee shall file with the Commission a report describing specific improvements to the Clackamas River Hatchery undertaken as a result of the monitoring program.

Article 46. Gravel Augmentation Below River Mill Dam

Within six months of license issuance, the Licensee shall, after consultation with the Fish Committee, file with the Commission, for approval, a detailed gravel augmentation plan consistent with Section IX and Appendix F of the Fish Passage and Protection Plan, below River Mill Dam. The Gravel Augmentation Plan will provide for (i) two years of baseline data collection and sediment transport modeling, (ii) completion of permitting and construction of necessary facilities within five years of license issuance, (iii) five years of initial augmentation, (iv) annual evaluation throughout the first five years of augmentation, (v) continued annual augmentation, as modified, in consultation with the Fish Committee, based on the first five years of augmentation, and (vi) the evaluation and modification, in consultation with the Fish Committee, of the Gravel Augmentation Plan every five years thereafter. Upon Commission approval, the Licensee shall implement the plan.

Article 47. Large Wood Management

(a) ***North Fork Reservoir:*** The Licensee shall manage large woody debris captured in the North Fork Reservoir in accordance with Section IX of the Fish Passage and Protection Plan, Exhibit D to the Settlement Agreement.

(b) ***Lake Harriet:*** The Licensee shall transport all woody debris captured in Lake Harriet around Lake Harriet Dam and place it back in the Oak Grove Fork below the dam or at the nearest feasible downstream access point in the Oak Grove Fork below Lake Harriet Dam.

139 FERC ¶ 62,213
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Portland General Electric Company | Project No. 2195-076

ORDER MODIFYING AND APPROVING HATCHERY SPRING CHINOOK SMOLT STOCKING PLAN UNDER ARTICLE 403

(Issued June 12, 2012)

1. On April 30, 2012, Portland General Electric Company (licensee) filed its Hatchery Spring Chinook Smolt Stocking Plan pursuant to Article 403 of the December 21, 2010 Order Issuing New License[1] for the Clackamas River Hydroelectric Project. The project consists of the North Fork, Faraday, River Mill, and Oak Grove developments and is located on the Oak Grove Fork of the Clackamas River and the mainstem of the Clackamas River in Clackamas County, Oregon.

BACKGROUND AND LICENSE REQUIREMENTS

2. Article 403 requires the licensee to file, for Federal Energy Regulatory Commission (Commission) approval, within one year of license issuance, a hatchery spring Chinook smolt stocking plan. The plan is to be prepared after consultation with the Fish Committee.[2] By Order Granting Extension of Time, issued February 17, 2012, the deadline to file the plan was extended to June 21, 2012. The plan is required to include: (a) the quantities and release locations of hatchery spring Chinook smolts to be released into the Clackamas River, beginning the first complete calendar year following license issuance and continuing for 10 years thereafter; (b) a description of the monitoring

[1] 133 FERC ¶ 62,281 (2010)

[2] The Fish Committee is comprised of the licensee and representatives from the National Marine Fisheries Service, U.S. Fish and Wildlife Service, U.S. Forest Service, Confederated Tribes of the Warms Springs Reservation of Oregon, Confederated Tribes of the Grand Ronde Community of Oregon, Confederated Tribes of the Siletz Indians of Oregon, Oregon Department of Fish and Wildlife, Oregon Department of Environmental Quality, Clackamas River Basin Council, Association of Northwest Steelheaders, and one representative of the following non-governmental organizations: Trout Unlimited, American Rivers, Oregon Trout, and Native Fish Society.

program for assessing the effects of the stocking program on wild fish, beginning the first complete calendar year following license issuance and continuing for ten years thereafter; and (c) a provision to file, for Commission approval, a report by January 1 of the eleventh year following the initiation of the stocking program that documents the results of the monitoring program.

LICENSEE'S PLAN

3. The licensee states that the Clackamas River spring Chinook program is a segregated program using broodstock from returns to the Clackamas River system with the purpose of providing harvest opportunities and to mitigate for the loss of production resulting from hydroelectric development in the watershed. Rearing and release strategies implemented by the Oregon Department of Fish and Wildlife (ODFW) at the Clackamas River Hatchery are designed to limit the amount of ecological interactions occurring between hatchery and naturally produced fish. Spring Chinook are released as full-term (yearling) smolts, although some (200,000) are released in the fall as sub-yearlings. Most spring Chinook smolts (870,000) are released in the spring as yearlings from the Clackamas Hatchery (Dog Creek) or one of several acclimation ponds located throughout the river. The acclimation ponds are located at the mouths of Clear and Foster creeks, in Eagle Creek at Eagle Fern Park, and at Cassidy Pond (river mile 8.5). The licensee's plan identifies the following release schedule for the ODFW spring Chinook program from 2012-2021:

Release Location	Release Timing	Release Size
Dog Creek	Early November	200,000
Dog Creek	Mid-April	380,000
Eagle Creek	Late March	80,000
Eagle Creek	Mid-April	80,000
Eagle Creek	Early May	80,000
Cassidy Pond	Early April	50,000
Foster Creek	Early April	50,000
Clear Creek	Late March	55,000
Clear Creek	Mid-April	55,000
Clear Creek	Early May	55,000

4. According to the licensee, in a recent review of hatchery programs across the Columbia basin, the Hatchery Scientific Review Group (HSRG)[3] did not make any

[3] The Hatchery Scientific Review Group (HSRG) is the independent scientific

recommendations for improving the Clackamas spring Chinook program. However, the HSRG did provide a number of recommendations related to ODFW's summer and winter steelhead programs intended to reduce the genetic and ecological risks to the naturally spawning (wild) population in the lower Clackamas River. As a result, the licensee states that the most significant, identifiable, and correctable risks posed by hatchery fish to wild fish in the Clackamas River are associated with the steelhead programs. Therefore, the licensee plans to estimate hatchery fish spawning and smolt production in the lower Clackamas basin to assess the potential impact of summer and winter hatchery steelhead on wild winter steelhead, with emphasis on impacts in the Clear Creek sub-basin.

5. The study would proceed in a phased approach, with progression to Phase 2 dependent on the findings of Phase 1, and likewise progression to Phase 3 would be dependent on findings in Phase 2. Phase 1 would begin in 2012 and continue for two years with the primary goal of determining the abundance of hatchery and wild steelhead spawning in Clear Creek. Phase 2 would occur in 2014 and 2015 and also determine abundance of hatchery and wild steelhead spawning in Clear Creek as well as include juvenile sampling to determine if spawning by hatchery steelhead is successful and if possible the level of genetic introgression among juveniles. Phase 3 would occur if the percentage of fish spawning in Clear Creek exceeds 10 percent, and significant genetic introgression is detected among outmigrating juveniles during Phase 2. Spawning ground surveys would be conducted in accordance with the ODFW Adult Salmonid Inventory and Sampling and occur from February through May in Clear Creek. The objective of the spawning ground surveys is to provide information, in addition to that gained at the collection weir, to estimate the percentage of hatchery fish and recycled fish among natural spawners. If all study phases are implemented, the project would conclude in 2019.

6. The licensee states that in the event that the monitoring efforts reveal opportunities for improvements to reduce impacts of hatchery fish on wild fish before the monitoring program has concluded, the Fish Committee would have the opportunity to recommend shortening the monitoring program and move forward implementing any identified improvement measures. The licensee would provide the Fish Committee with an annual report of results from the previous work year by February 1 of each year, beginning 2014. Upon completion of the project, but no later than February 1, 2021, a final project report would be prepared and provided to the Fish Committee for review prior to filing with the

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panel established and funded by Congress to provide an autonomous and credible evaluation of hatchery reform as part of the Puget Sound and Coastal Washington Hatchery Reform Project.

Commission. The final report would summarize all data collected during the project, summarize findings, and provide any recommendations to reduce the potential impacts of hatchery fish to wild fish.

AGENCY CONSULTATION

7. Article 403 requires the licensee to prepare its plan in consultation with the Fish Committee. The licensee's filing included documentation of consultation with the Fish Committee, including comments and the licensee's response to those comments which were incorporated into the licensee's filed plan. By emails dated April 12, April 13, and April 16, and April 24, 2012, and included in the licensee's filing, the U.S. Forest Service, the FWS, NMFS, and the ODFW, respectively, approved the licensee's plan.

DISCUSSION AND CONCLUSION

8. Article 403 requires the licensee to file, for Commission approval, its final report by January 1 of the eleventh year following the initiation of the stocking program. However, the licensee proposes to provide its final report to the Fish Committee no later than February 1, 2021, for a 30-day review and comment period prior to filing its report with the Commission based upon the program's scheduled completion date in 2019. We would then expect the licensee to file its final report for Commission approval by March 15, 2021. As stipulated under Article 403, the final report should document the results of the monitoring program, and include any proposals for measures to reduce the adverse effects of hatchery fish on wild fish.

9. The licensee's plan should assist in ensuring that the quantities and release locations of hatchery spring Chinook smolts to be released into the Clackamas River are implemented according to its plan for each year of the program. Additionally, the licensee's monitoring program should assist in assessing the effects of hatchery spring Chinook and other salmonid stocking on wild fish in the Clackamas River while identifying any proposed measures to reduce any such adverse effects on wild fish.

10. The licensee's Hatchery Spring Chinook Smolt Stocking Plan satisfies the requirements of Article 403 under the December 21, 2010 Order Issuing New License for the Clackamas River Hydroelectric Project and, as modified, should be approved.

The Director orders:

(A) Portland General Electric Company's (licensee) Hatchery Spring Chinook Smolt Stocking Plan, filed April 30, 2012, pursuant to Article 403 of the December 21, 2010 Order Issuing New License for the Clackamas River Hydroelectric Project, as modified by paragraph (B), is approved.

(B) The licensee shall file, for Federal Energy Regulatory Commission (Commission) approval, its Final Hatchery Spring Chinook Stocking Report by March 15, 2021. The report shall include the results of the monitoring program, and include any proposals for measures to reduce adverse effects of hatchery fish on wild fish. The licensee shall allow the Fish Committee 30 days to review and comment on the report prior to filing with the Commission. The report shall include any Fish Committee comments and the licensee's response to any such comments or recommendations. The Commission reserves the right to make changes to the plan based upon review of its annual and final monitoring reports.

(C) The licensee shall file any document required by this order with the Secretary of the Commission. Filings may be submitted electronically via the Internet; see the instructions on the Commission's website under the "e-filing" link. In lieu of electronic filing, an original and eight copies of all documents may be mailed to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, Mail Code: DHAC, PJ-12.7, 888 First Street, N.E., Washington, D.C. 20426.

(D) This order constitutes final agency action. Any party may file a request for rehearing of this order within 30 days from the date of its issuance, as provided in section 313(a) of the Federal Power Act, 16 U.S.C. § 8251 (2006), and the Commission's regulations at 18 C.F.R. § 385.713 (2011). The filing of a request for rehearing does not operate as a stay of the effective date of this order, or of any other date specified in this order. The licensee's failure to file a request for rehearing shall constitute acceptance of this order.

Thomas J. LoVullo
Chief, Aquatic Resources Branch
Division of Hydropower Administration
and Compliance

Agreement (see Settlement Exhibit C; Proposed License Article 9).

f. *Fish Passage*
PGE shall improve fish passage through the Project facilities as specified in the Settlement Agreement (see Settlement Exhibit D; Proposed License Article 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29 30, 31, 32, 33, 34, 35, 36, 37, 38, 40, and 41).

g. *Evaluation of Fish and Aquatic Life Mitigation Effectiveness*
PGE shall perform, or allow the Oregon Department of Fish and Wildlife (ODFW) to perform, any tests or studies required by ODFW to evaluate the effectiveness of measures for the protection of fish and aquatic life as described in the Settlement Agreement (see Settlement Exhibit D; Proposed License Article 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29 30, 31, 32, 33, 34, 35, 36, 37, 38, 40, and 41).

h. *Habitat Enhancement and Large Wood*:
PGE shall implement the following habitat projects as specified in the Settlement Agreement:
(1) Construct habitat projects in Dinger Creek (see Settlement Exhibit D, Proposed License Article 42).
(2) Disrupt Brook Trout and Kokanee spawning in Timothy Lake Tributaries (see Settlement Exhibit D; Proposed License Article 42).
(3) Construct habitat structures in the Oak Grove Fork downstream of Timothy Dam (see Settlement Exhibit D; Proposed License Article 42).
(4) Restore side channels in the Lower Oak Grove downstream of Harriett Dam (see Settlement Exhibit D; Proposed License Article 44).
(5) Construct habitat projects in the mainstem of the Lower Oak Grove Fork downstream of Harriett Dam (see Settlement Exhibit D; Proposed License Article 44).
(6) Implement the Plan for Large Woody Debris pertaining to Harriett Dam and the North Fork Reservoir (see Settlement Exhibit D; Proposed License Article 47).
(7) Implement the Wetland Mitigation Plan (see Settlement Exhibit I; Proposed License Article 52).
(8) Implement the Vegetation Management Plan (see Settlement Exhibit E-2; Proposed License Article 51).

i. *Sediment Transport*
PGE shall implement the following programs with regard to sediment transport as specified in the Settlement Agreement:
(1) Implement the Gravel Augmentation Program downstream of River Mill Dam (see Settlement Exhibits D and F; Proposed License Article 46).
(2) Implement the gravel augmentation program in the Lower Oak Grove Fork (see Settlement Exhibit D; Proposed License Article 44).

j. *Mitigation and Enhancement Fund*
PGE shall establish and oversee the Mitigation and Enhancement Fund as specified in the Settlement Agreement (see Settlement Exhibit H; Proposed License Article 48).

k. *Monitoring*
PGE shall conduct all monitoring, recording, and reporting specified in the revised WQMMP and in the Settlement Agreement and associated exhibits, including but not limited to monitoring of water quality, project operations, stream flow, ramping rates, and reservoir levels.

l. *Temperature Load Allocation Downstream of River Mill Dam*
(1) Within six months of issuance of a new FERC license, PGE shall develop and submit for DEQ approval a plan to implement either a seasonal drawdown of Faraday Lake, or a channelization of Faraday Lake that would produce a comparable temperature reduction at the Faraday tailrace, as specified in the Modified Proposed License Article 14 submitted to FERC on July 21, 2008.
(2) PGE shall implement the Gravel Augmentation Program as specified in the Settlement Agreement (see Settlement Exhibit D, Appendix F; Proposed License Article 46).

m. *Implementation*
PGE shall, prior to implementation or construction of any measures required under these Certification Conditions, provide evidence to DEQ that PGE has received all required approvals and permits, including but not limited to approvals as set forth in the Settlement Agreement by "Fish Agencies" as defined in the Settlement Agreement.

n. *Spill and Waste Management*
PGE shall maintain and implement current Spill Prevention, Control, and Countermeasure (SPCC) plans for oil and hazardous materials, prepared in accordance with 40 CFR 112. These plans shall address all locations at the Project where Project operations have the potential to result in a spill or release or threatened spill or release to the Clackamas River, Oak Grove Fork, or any other water of the state in the vicinity of Project operations. In the event of a spill or release or threatened spill or release to such waters, PGE shall immediately implement the SPCC plans and notify the Oregon Emergency Response System (OERS) at 1-800-452-0311.

<u>9. General</u>

a. *Schedules*
Unless otherwise specified in the WQMMP or the Settlement Agreement, actions required of PGE under these § 401 Certification Conditions, including but not limited to adaptive management evaluations and modifications, shall be performed in accordance with such reasonable schedules as specified in writing by DEQ for the action.

Appendix B-5
2015 Draft Annual Test and Verification Study Plan
Physical Reservoir Changes with Selective Water Withdrawal

Megan Hill Megan.Hill@pgn.com
James Bartlett James.Barlett@pgn.com
December 2014

The Physical Reservoir Changes with Selective Water Withdrawal (SWW) Test and Verification (T&V) study was to be conducted for three years after the SWW became operational (PGE and CTWS 2008). The majority of the study objectives were completed during 2010-2012 when we conducted drogue and smolt movement studies and evaluated water quality model predictions (Campbell et al. 2012). One additional requirement of the test and verification study not yet completed is to use Acoustic Doppler Current Profiler to measure the depth, velocity and direction of the current patters in the three arms of Lake Billy Chinook and the Round Butte Dam forebay. This objective was postponed until deemed necessary. For the reasons discussed below we plan to conduct a forebay flow study in 2015; the Lake Billy Chinook study will be conducted in 2016.

Background

In 2013 we studied salmonid smolt behavior in the Round Butte Dam forebay using acoustic telemetry. An acoustic telemetry array, consisting of nine hydrophones, was deployed in front of the SWW to determine movement patterns of smolts near the SWW. The 2013 data showed relatively high levels of use in areas associated with the SWW access bridge and to the south of the SWW entrances (Hill et al. 2014). Flow data was not measured so reservoir current and smolt movement relationships are unknown. In addition, the forebay flow dynamics were not modeled for the SWW as constructed, and the area of the zone of influence (defined as the region where velocity is greater than 12 cm/s during SWW construction) is unknown. Understanding the currents that fish experience in the forebay may help explain their behavior and point to a potential solution. For example, one potential solution that has been proposed to increase fish capture is to install a guidance net. Another potential solution is to increase turbulent flow in the vicinity of the SWW (as described in Coutant 2001). Data on forebay flow dynamics is necessary to evaluate these and other potential solutions to increase fish collection efficiencies at the SWW. To meet water temperature requirements for the lower Deschutes River as described in the *Water Quality Management and Monitoring Plan* (PGE and CTWS 2004), it has been necessary to initiate bottom water withdrawal in May rather than in July, as predicted by pre-SWW modeling. It is unknown what impact the early initiation of bottom withdrawal has on fish collection efficiency or on the zone of influence. For these reasons, PGE has submitted a request for proposals to contractors to conduct a forebay flow study.

Objectives

The specific objectives of this study are to:

1) Develop a flow and velocity map (including fluctuating velocities) that extends north,

south, and east 240 m from the back of the SWW top structure and to a depth of 20 m (Figure 1).

Figure 1. Flow and velocity map design in relation to SWW.

2) Identify the "zone of influence," the length of area located in front of the SWW intakes that provides fish attraction (velocity and depth) at various and fluctuating generation flows.
3) Identify the effect of bottom withdrawal on flows within the forebay and the zone of influence.

Methods

Specific methods and timelines will be developed with the selected contractor and presented to the Fish Committee prior to initiating the study.

References

Campbell, L., D. Ratliff, M. Hill. 2012. Physical Reservoir Changes with Selective Water Withdrawal Test and Verification Study: 2011 Monitoring Report. Portland General Electric. Portland, Oregon.

Coutant, C.C. 2001. Turbulent attraction flows for guiding juvenile salmonids at dams. In. Coutant, C.C. (Ed), *Behavioral Technologies for Fish Guidance: American Fisheries Society Symposium 26* (pp. 57-78). American Fisheries Society, Bethesda, MY.

Hill, M., C. Quesada, M. Bennett, M. Timko, M. Martinez, S. Rizor, C. Wright, L. Sullivan, M. Meagher, T. Kukes. 2014. Evaluation of juvenile Chinook salmon and steelhead downstream passage behavior and resident bull trout behavior at Round Butte Dam, Madras, Oregon. Blueleaf Environmental, Ellensburg, WA.

Portland General Electric Company (PGE) and Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). 2004. Pelton Round Butte Project Water Quality Management Plan *in* Settlement Agreement Concerning the Relicensing of the Pelton Round Butte Hydroelectric Project FERC Project No. 2030.

Portland General Electric Company (PGE) and Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). 2008. Physical Reservoir Changes with Selective Water Withdrawal. Portland General Electric. Portland, OR.

Commission determines that downstream fish passage should be reinitiated, the licensees shall develop a fish passage plan based on the new information then available. Such plan shall be developed in consultation with the Fish Committee and Fish Agencies. The licensees shall include with the plan, an implementation schedule, documentation of consultation, copies of comments and recommendations on the completed plan after it has been prepared and provided to the Fish Committee and Fish Agencies, and specific descriptions of how the Committee's and Agencies' comments are accommodated by the plan. The licensees shall allow a minimum of 30 days for the Fish Committee and Fish Agencies to comment and to make recommendations before filing the plan with the Commission. If the licensees do not adopt a recommendation, the filing shall include the licensees' reasons, based on project-specific information.

The Commission reserves the right to require changes to the plan. Implementation of the plan shall not begin until the plan is approved by the Commission. Upon Commission approval, the licensees shall implement the plan, including any changes required by the Commission.

Article 419. ***Fish Health Management Program.*** Within 18 months of license issuance, the licensees shall file for Commission approval a plan for a fish health management program at the project to support the fish passage effort, and to monitor disease incidence in Deschutes River fish populations and potential changes in the distribution of fish disease agents. The plan shall include provisions for fish health services and supplies associated with production of salmon and steelhead eggs and fry at Round Butte Hatchery as part of the Reintroduction Plan, diagnosis of disease in mortalities at fish facilities, and monitoring of disease agents in wild fish populations. The plan shall also include provisions for fish pathogen procedures developed in consultation with the Oregon Department of Fish and Wildlife Fish Health Services staff (ODFW) for trap-and-haul and volitional passage programs. The licensees shall include with the plan an implementation schedule that provides for implementation of the plan throughout the Interim Passage Phase and the first five years of the Final Passage Phase (or for the first 15 years of the Interim Passage Phase if transition to the Final Passage Phase does not occur).

The program shall provide for the evaluation of disease as a mortality factor in downstream and upstream migrating anadromous salmonids, to reduce the risk of transmitting new serious disease pathogens upstream, and other fish health management activities associated with the fish passage program. This requirement may be accomplished through an agreement with ODFW.

The licensees shall prepare the plan in consultation with the Fish Committee established by Article 402 and the Fish Agencies (National Marine Fisheries Service, U.S. Fish and Wildlife Service, ODFW, and Warm Springs Branch of Natural Resources). The licensees shall include with the plan documentation of consultation, copies of comments and recommendations on the completed plan after it has been prepared and provided to the Fish Committee and Fish Agencies, and specific descriptions of how the Committee's and Agencies' comments are accommodated by the plan. The licensees shall allow a minimum of 30 days for the Fish Committee and Fish Agencies to comment and to make recommendations before filing the plan with the Commission. If the licensees do not adopt a recommendation, the filing shall include the licensees' reasons, based on project-specific information.

The Commission reserves the right to require changes to the plan. Implementation of the plan shall not begin until the plan is approved by the Commission. Upon Commission approval, the licensees shall implement the plan, including any changes required by the Commission.

Article 420. ***Round Butte Hatchery.***

(a) ***Hatchery Agreement*:** Within six months of license issuance, the licensees shall enter into with Oregon Department of Fish and Wildlife (ODFW) and file with the Commission, for approval, the "Agreement Related To The Operation Of The Round Butte Hatchery And Related Facilities" (the "Hatchery Agreement"), substantially consistent with the draft agreement included in Appendix B to the Settlement Agreement.

(b) ***Hatchery Operations*:** Within one year of license issuance, the licensees shall file for Commission approval a plan for hatchery operations at Round Butte Hatchery at no more than current production levels of spring Chinook and summer steelhead, as specified in section 8 of Appendix B of the Settlement Agreement, during the term of the license, which hatchery operations shall be consistent with: (1) the annual work plan developed under Condition 16 of Appendices C and D; (2) then-in-existence fish management policies and directives of ODFW and the Confederated Tribes of the Warm Springs Reservation Branch of Natural Resources (CTWS BNR); (3) any Hatchery Genetics Management Plan or other directive developed between ODFW and the National Marine Fisheries Service (NOAA Fisheries) pursuant to the Endangered Species Act (ESA); and (4) the priority objective of restoring and recovering wild stocks in the Deschutes River basin. To ensure consistency with the Fish Passage Plan, the licensees shall consult with the Fish Committee established by Article 402 regarding hatchery operations. The licensees shall include with the plan, an implementation schedule, documentation of consultation, copies of comments and recommendations on the completed plan after it has been prepared and provided to the Fish Committee, and specific descriptions of how the Committee's comments are accommodated by the plan. The licensees shall allow a minimum of 30 days for the Fish Committee to comment and to make recommendations before filing the plan with the Commission. If the licensees do not adopt a recommendation, the filing shall include the licensees' reasons, based on project-specific information.

The Commission reserves the right to require changes to the plan. Implementation of the plan shall not begin until the plan is approved by the Commission. Upon Commission approval, the licensees shall implement the plan, including any changes required by the Commission.

(c) ***Hatchery Improvements:*** Within six months of entering into the Hatchery Agreement with ODFW or one year of license issuance if agreement is not reached, the licensees shall, after consultation with the Fish Committee, file for Commission approval a hatchery improvement plan to implement the hatchery improvements identified in the Hatchery Agreement if such an agreement is reached or the draft agreement included in Appendix B to the Settlement Agreement if agreement is not reached. The licensees shall include with the plan, an implementation schedule, documentation of consultation, copies of comments and recommendations on the completed plan after it has been prepared and provided to the Fish Committee, and specific descriptions of how the Committee's comments are accommodated by the plan. The licensees shall allow a minimum of 30 days for the Fish Committee to comment and to make recommendations before filing the plan with the Commission. If the licensees do not adopt a recommendation, the filing shall include the licensees' reasons, based on project-specific information.

The Commission reserves the right to require changes to the plan. Implementation of the plan shall not begin until the plan is approved by the Commission. Upon Commission approval, the licensees shall implement the plan, including any changes required by the Commission.

(d) ***Sockeye*:** If the Fish Committee believes that hatchery supplementation is necessary in order to reestablish an anadromous population of sockeye above Round Butte dam, the licensees shall file a plan with the Commission, for approval, to undertake the necessary changes in equipment to support hatchery capacity at the Round Butte Hatchery or provide funding to ODFW to undertake such changes for the production of sockeye. The licensees shall include with the plan, an implementation schedule, documentation of consultation, copies of comments and recommendations on the completed plan after it has been prepared and provided to the Fish Committee, and specific descriptions of how the Committee's comments are accommodated by the plan. The licensees shall allow a minimum of 30 days for the Fish Committee to comment and to make recommendations before filing the plan with the Commission. If the licensees do not adopt a recommendation, the filing shall include the licensees' reasons, based on project-specific information.

The Commission reserves the right to require changes to the plan. Implementation of the plan shall not begin until the plan is approved by the Commission. Upon Commission approval, the licensees shall implement the plan, including any changes required by the Commission.

If the Fish Committee determines that hatchery supplementation is not necessary in order to reestablish an anadromous population of sockeye above Round Butte dam, the licensee shall file for Commission approval written notification of and justification for the Committee's decision.

(e) ***Periodic Review:*** Every five years after issuance of the license, the licensees, in cooperation with ODFW and CTWS BNR to the extent of their interests in participating, shall conduct a periodic review, to be funded by the licensees, of the hatchery program to determine whether it is meeting its goals. The review shall consider federal, ODFW and CTWS BNR fish management policies and directives, any Hatchery Genetics Management Plan or other directive developed between ODFW and NOAA Fisheries pursuant to the ESA, relevant best practices, and existing information regarding recent scientific advances, and shall include recommendations for ongoing management of the hatchery program for the next five years. The licensees shall make the draft hatchery review available to the Fish Committee for review and comment. The licensees also shall make the draft hatchery review available for public review and comment through an annual workshop or other appropriate forum. The licensees shall provide notice of the annual workshop to all Settlement Agreement parties and the Commission. The licensees shall allow a minimum of 30 days for the consulted parties to comment prior to finalizing the hatchery review and filing it with the Commission. The licensees shall specify in the final review how any comments and recommendations were addressed.

If the licensees, ODFW, and CTWS BNR believe in the final review that the hatchery program is not supporting the goals of the Fish Passage Plan or supporting the goals of self-sustaining harvestable fisheries in the lower Deschutes River, the licensees shall consult with ODFW and CTWS BNR regarding changes that may be made to hatchery operations. If ODFW and CTWS BNR believe that changes to hatchery operations are necessary, the licensees shall file a plan with the Commission, for approval, to undertake the necessary changes or provide funding to ODFW to undertake such changes for the purposes of supporting the goals of the Fish Passage Plan or self-sustaining harvestable fisheries in the lower Deschutes River. The licensees shall include with the plan, an implementation schedule, documentation of consultation, copies of comments and recommendations on the completed plan after it has been prepared and provided to the agency and Tribe, and specific descriptions of how the agency's and Tribes' comments are accommodated by the plan. The licensees shall allow a minimum of 30 days for the agency and the Tribe to comment and to make recommendations before filing the plan with the Commission. If the licensees do not adopt a recommendation, the filing shall include the licensees' reasons, based on project-specific information.

The Commission reserves the right to require changes to the plan. Implementation of the plan shall not begin until the plan is approved by the Commission. Upon Commission approval, the licensees shall implement the plan, including any changes required by the Commission.

(f) If the agreement specified in item (a) is not reached, the licensees shall file for Commission approval written explanation of the dispute, including the positions taken, in lieu of filing the agreement. In the event agreement is not reached, the licensees shall remain responsible for completing items (b) through (f) of this article. The Commission reserves the right to require additional measures consistent with the terms of this article or modifications to this article in the event the agreement in item (a) is not reached.

Article 421. ***Native Fish Monitoring Program.*** The licensees shall, within one year of license issuance, file for Commission approval, after consultation with the Fish Committee established by Article 402, a native fish monitoring plan to evaluate effects of reintroducing anadromous fish on resident fish populations. The plan shall include the following biological and habitat components:

(a) Biological Components:

(1) Sockeye, steelhead, and spring Chinook spawning surveys, at locations and times determined by the Fish Committee, to assess spawning escapement, distribution, and timing for fish passed above the dams; redd counts in tributaries to Lake Billy Chinook, including the Metolius River system and Squaw Creek; and annual salmon and steelhead spawning surveys and redd counts beginning the first year that returning adult anadromous fish are passed upstream of the project and continuing after initiation of downstream passage for the length of time (about 12 years) required for three generations of adults to return. This salmon/steelhead spawning monitoring shall continue on an annual basis until the ratio of recruits to spawners (R/S ratio) is ≥ 1, whereupon the licensees shall notify the Commission that an R/S ratio of ≥ 1 has been reached. Thereafter, as long as the R/S ratio remains ≥ 1, the licensees are under no obligation to continue the spawning monitoring unless recommended by the Fish Committee and approved by the Commission. In the event that the R/S ratio decreases to <1, the licensees shall notify the Commission, and annual spawning monitoring shall be resumed until the R/S ratio is again ≥ 1.

(2) Monitoring of competition among anadromous and resident fish species in the Metolius and middle Deschutes River systems and McKay Creek following reintroduction of steelhead and salmon upstream of the project, using a combination of population monitoring and redd counts, including the following:

Confederated Tribes of the Warm Springs Reservation of Oregon

P. O. Box 960, Warm Springs, OR 97761

Portland General Electric
121 S.W. Salmon, Portland, OR 97204

March 23, 2006

Project No. 2030 – Oregon
Pelton Round Butte Hydroelectric Project

ELECTRONICALLY FILED

Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Project No. 2030 – Pelton Round Butte Hydroelectric Project – Article 420(a) - Round Butte Hatchery Agreement

Dear Secretary Salas:

Portland General Electric Company ("PGE") and the Confederated Tribes of the Warm Springs Reservation of Oregon ("CTWS"), are the Joint Licensees for the Pelton Round Butte Hydroelectric Project (Project No. 2030). On June 21, 2005, the Commission issued an Order Approving Settlement and Issuing New License, *Portland General Electric Company & Confederated Tribes of the Warm Springs Reservation of Oregon*, 111 FERC ¶ 61,450 (2005).

Article 420(a) of the License requires the Joint Licensees to enter into an agreement with the Oregon Department of Fish and Wildlife ("ODFW"), and file with FERC for approval, an agreement related to the operation of the Round Butte Hatchery and related facilities (the "Hatchery Agreement"). The original deadline for filing the Hatchery Agreement with the Commission was December 21, 2005. However, on January 31, 2006, the Commission granted the Joint Licensees' December 14, 2005, request for a six-month extension by FERC to file the Hatchery Agreement.

The Hatchery Agreement was signed on January 31, 2006, and is attached for filing with the Commission pursuant to Article 420(a) of the Project license.

Please don't hesitate to call me (503.464.8864) regarding any questions or comments regarding this filing.

Very truly yours,

Julie A. Keil, Director
Hydro Licensing
Portland General Electric Company

Fish Committee

AGREEMENT RELATED TO THE OPERATION OF THE ROUND BUTTE HATCHERY AND RELATED FACILITIES

This Agreement is entered into this __________ day of January, 2006, by and among PORTLAND GENERAL ELECTRIC COMPANY ("PGE") an Oregon corporation and the CONFEDERATED TRIBES OF THE WARM SPRINGS RESERVATION OF OREGON ("CTWS") (collectively "the Licensees") and the STATE OF OREGON, acting by and through the OREGON DEPARTMENT OF FISH AND WILDLIFE ("ODFW").

RECITALS

WHEREAS, PGE and CTWS are the Licensees for the Pelton Round Butte Project, FERC Project No. 2030 ("Project"), a new license for which was issued on June 21, 2005; and

WHEREAS, the Licensees, ODFW and other parties entered into a Settlement Agreement dated July 13, 2004 ("Settlement"), the terms of which require that the Licensees continue funding of operations of the Round Butte Fish Hatchery and related facilities as defined below; and

WHEREAS, the Licensees and ODFW intend that, upon its Effective Date, as defined below, this Agreement shall supersede and replace all previous agreements between PGE and ODFW regarding Hatchery operations, including that certain June 1970 Agreement for the operation of the Round Butte Hatchery.

THEREFORE, in consideration of the foregoing recitals and the mutual terms and conditions set forth herein the Licensees and ODFW (collectively the "Parties") hereby agree as follows:

1. <u>Purpose and Intent</u>

The purpose of this Agreement is to assure successful and cost-effective operation of the Round Butte Hatchery (hereafter the "Hatchery" as further defined under §3 below) located at Round Butte Dam on the Deschutes River, Oregon.

The intent of the Parties is to operate and maintain the Hatchery as necessary to provide the numbers of spring Chinook, salmon and steelhead trout for existing fisheries, as well as other species, as may be mutually agreed.

The Parties further agree that the Hatchery will be operated to both support the goals of the Settlement's "Fish Passage Plan" and to support the goals of self-sustaining and harvestable fisheries in the lower Deschutes River. The multiple purposes of the Hatchery will require close coordination among the Parties on an ongoing basis.

2. **Effective Date; Term**

The effective date of this Agreement (the "Effective Date") shall be the date on which this Agreement is fully executed, approved and delivered in accordance with applicable laws, rules and regulations. Unless earlier terminated as provided elsewhere herein, the term of this Agreement shall commence on the Effective Date and will continue for the duration of the new FERC license for the Project, and any annual licenses issued subsequent to the expiration of that license (the "Term"); provided however, that this Agreement may be terminated by mutual consent of both Parties if, during the Term, and according to the terms of the Settlement, the Hatchery is determined to no longer be needed to achieve the goals of the fisheries mitigation program required by the Settlement and the new FERC license.

3. **Funding**

The Licensees shall provide all funding for the operations, maintenance, and agreed upon capital improvements for the Hatchery, which is defined for purposes of this Agreement to include the fish production facilities located at Round Butte Dam, the rearing facilities located in the Pelton Fish Ladder, the fish trapping and sorting facilities located at the reregulating dam, all necessary and related equipment including vehicles and the three hatchery houses and associated buildings located near the Project offices. Throughout the Term of this Agreement, and in accordance with §4, Licensees shall provide annual funding for Hatchery operations as provided herein.

4. **Budget**

a. Budgets for operation and maintenance of the Hatchery shall be developed in accordance with each State of Oregon fiscal biennium.

b. In addition, an annual budget shall be prepared by April 15th of each year. This annual budget shall be presented by quarter, with annual totals, and include appropriate line item breakdowns within the following general budget categories: personnel services, services and supplies, indirect charges, contract services, and capital or non-expendable equipment or improvements (including justification for proposed capital improvements or property acquisitions). A budget year is the 12 month period from July 1st to June 30th beginning after the Effective Date.

c. To the extent agreed to by the Parties, the annual budget for Hatchery operations and maintenance items will be included in the annual operating budget for the Project.

d. Capital items which are agreed by the Parties as being necessary for the health and safety of ODFW employees, necessary for the continued operation of the Hatchery at agreed upon production levels outlined in §8, or required by the terms of the Settlement's Fish Passage Plan shall be funded by the Licensees as provided in the approved annual budget and AOP (defined below). Plans for implementing any changes to Hatchery facilities required by the Settlement's Fish Passage Plan will be developed cooperatively by the Licensees and ODFW and reflected in the AOP. Other capital items identified in the approved AOP and annual budget shall be subject to the Licensees' then- in- effect capital funding and allocation process.

e. Within 30 days of receipt of ODFW's proposed annual budget, the Licensees and ODFW shall meet to approve or propose revisions to the annual budget. ODFW and the Licensees shall attempt to negotiate a resolution to any disputed portions of the annual budget. Both Parties shall seek to approve a final annual budget by June 15. If the Parties cannot reach agreement on the annual budget and that budget year commences, then the annual budget for that budget year, except for the disputed portions, shall take effect. If excluding the disputed portion of the annual budget would make continued Hatchery operations impractical, then ODFW shall operate the Hatchery and the Licensees shall provide funding in accordance with the budget for the most recent preceding year, until the dispute is resolved.

f. ODFW must receive written approval from the Licensees for major changes to an annual budget, including: (1) changes of substance in position activities, (2) changes in the amount of any approved budget category that would alter the total budget amount in that category by more than 5 percent, and (3) any change in the amount of any general budget category that would result in an increase in the total annual budget amount by 5 percent or more. ODFW shall request approval as soon as is practicable after the need for such change becomes known. ODFW shall include with such request documentation adequate to justify requested budget changes, capital improvements or acquisition of materials, equipment or supplies.

g. ODFW shall be reimbursed at monthly intervals by the Licensees for the costs and expenses incurred by ODFW in fulfilling its obligations under this Agreement and in accordance with the approved budget for that year.

5. <u>Annual Operating Plans (AOP)</u>

a. By April 15 of each year ODFW shall submit a proposed annual operating plan ("AOP"), including an annual budget, to the Licensees, for the operation and maintenance of the Hatchery for the following budget year. ODFW shall operate the Hatchery in accordance with: (1) the approved AOP and annual budget, (2) applicable policies and regulations of the State of Oregon; (3) any Hatchery Genetics Management Plan or other directive developed between ODFW and NOAA Fisheries pursuant to the Endangered Species Act, and (4) this Agreement.

b. The AOP shall set forth details of the operation of the Hatchery and include:

1. A production plan, which shall specify the species, broodstock sources and the annual production goal for each specie to be produced at the Hatchery. Current production goals are outlined under §8. The production plan will contain an assessment of the production plan's consistency with the Settlement's Fish Passage Plan.
2. A release plan, which shall identify by species and weight the rearing schedule and planned distribution of fish and the schedules and locations for releases.

a. Current target production levels funded by the Licensees of yearling smolts are 162,000 steelhead and 240,000 spring Chinook.

b. Total weight of smolts produced shall not exceed 78,000 pounds annually. In addition to these smolts produced for release into the lower Deschutes River, up to 30,000 post-smolt steelhead will be released into Lake Simtustus (15,000 pounds) as catchable trout.

c. Actual production numbers and release sizes shall not exceed 110% of the Hatchery production goals stated herein, unless otherwise agreed to in writing or expressed in the AOP.

d. To the extent consistent with ODFW's "Basin Fish Management Plan for the Deschutes and its Tributaries" and consistent with harvest goals, any changes to the species composition must be agreed to in the AOP.

e. Additional fish or species may be reared at the Hatchery if funded by other monies and included in an applicable basin management plan.

f. Fish will be marked as necessary for evaluation and fisheries management purposes.

In addition, the Hatchery will produce eyed eggs and fry needed to support the Settlement's Fish Passage Plan as outlined in the AOP.

9. Relation to the Settlement's Fish Passage Plan

The Hatchery AOP shall be consistent with the activities planned in the annual work plan to be developed under the Settlement's Fish Passage Plan. The Settlement's Fish Passage Plan annual work plan and the previous year results will be presented at an annual fisheries workshop where passage studies will be presented. ODFW shall be given a draft of the Settlement's Fish Passage Plan annual work plan in advance of its preparation of the Hatchery AOP to facilitate preparation of the Hatchery AOP.

If there are conflicts between the Hatchery AOP and the Settlement's Fish Passage Plan's annual work plan, the Parties will attempt to reconcile the plans through discussion between the Licensees' lead fish biologist, ODFW staff, and CTWS Department of Natural Resources (DNR) staff.

10. Periodic Review

Following issuance of the new FERC license, the Licensees and ODFW shall conduct a periodic review of the overall Hatchery program once every five (5) years. The Licensees and ODFW shall make the five year Hatchery review available to the Settlement's Fish Committee (FC) for review and comment. In addition, the periodic review will be incorporated into the annual fisheries workshop open to the public. If the periodic review finds that the Hatchery program is not meeting the goals of the Settlement Agreement, the FC may recommend the necessary changes to Licensees and to ODFW, which changes would be addressed in ODFW's subsequent draft AOP.

11. Additional Facilities

In addition to any capital improvements provided pursuant to §4 of this Agreement, the Licensees shall design and construct the following additional facilities, or upgrades to existing Hatchery facilities:

a. Facilities necessary to implement the reintroduction provisions of the Settlement's Fish Passage Plan: If the Settlement's Fish Passage Plan requires the addition of sockeye production before ODFW had authorized the reduction of spring Chinook and steelhead production at the Hatchery (pursuant to a revised basin management plan), and if no physical capacity is otherwise available at the Hatchery, the Licensees will either: (1) fund sockeye production on an interim basis at another agreed upon location; or (2) build the necessary additional facilities at the Hatchery. The Parties acknowledge and agree that the Hatchery, at current production goals outlined under §8, is operating at maximum physical capacity.

b. Facilities necessary for the implementation of the Fish Health provisions of the Settlement's Fish Passage Plan, prior to the implementation of the Settlement's Fish Passage Plan, which include:

    1. Ponds (temporary or permanent) for holding fish.
    2. Fish health examination and storage area, including a heated work area to store supplies and equipment for fish health studies (36-50 square ft) and sufficient space for a table, chair, electrical outlets, and access to a sink.
    3. Adequate isolation facilities to meet the Settlement's Fish Passage Plan requirements.

c. Changes to the ladder rearing sections necessary to comply with the applicable NPDES permit.

d. Other changes to the Hatchery:

    1. Sound barriers in the offices
    2. Improved septic system

e. Pelton Trap improvements:

    1. Heated and lighted work space
    2. Motorized hopper gate
    3. Repair to truck's plumbing for filling water with flexible hose.
    4. Upgraded alarm system

12. Hatchery Operation and Supervision

a. ODFW shall have sole authority over, and responsibility for, all matters related to employment and supervision of ODFW employees and, except as outlined elsewhere herein, ODFW shall have sole authority over the duties of ODFW employees at the Hatchery. Supervision of the fish production and operation of the Hatchery is the specific responsibility of ODFW and the ODFW Hatchery manager and staff, and shall be conducted by ODFW in accordance with the most current industry standards, applicable permits, fishery culture and management techniques and industry practices.

b. ODFW shall provide all necessary training for ODFW employees, including general safety training and training on the specific equipment required for Hatchery operations.

c. Currently, operation of the Pelton Fish Trap is handled by ODFW. However, it is the intent of the Parties that operation of the Pelton Fish Trap and transportation of any fish shall become the responsibility of the Licensees' Project fisheries staff, to be conducted as described in the Settlement's Fish Passage Plan, and to be subject to state and federal oversight for compliance with the ESA, the Settlement's Fish Passage Plan performance criteria and fish management statutory and administrative rules. Transition of operation and management of the Pelton Fish Trap from ODFW to Licensees' will occur during 2006 (as the Settlement's Fish Passage Plan is initiated) with collection of brood stock for gametes and juvenile fish to be placed in tributaries of the upper basin. Operation of the Pelton Fish Trap and transportation of fish will be coordinated with an ODFW NRS 3-level employee ("NRS 3") and the Hatchery manager to provide appropriate fish for brood stock for the Hatchery and fish passage. The Licensees shall be responsible for the collection, and delivery to ODFW, of the necessary brood stocks to allow ODFW to meet the annual production goals specified herein. The Licensees shall ensure that all fish handling at the Pelton Trap is: (1) conducted in consultation with ODFW and in a manner consistent with the AOP; and (2) conducted in accordance with: (a) fish culture and management techniques that are reasonably acceptable to ODFW, (b) standard industry practices, and (c) applicable statutory and administrative requirements. The Licensees shall provide all information on fish handling and transportation to ODFW staff within a reasonable time but in any event within fourteen (14) days of delivery.

d. During the "Interim Phase" and the first five years of the "Final Phase" (as those terms are defined in the Settlement Agreement) of the Settlement's Fish Passage Plan, the Licensees shall fund, among other positions, the above referenced NRS 3 position together with associated salary, services and supplies, capital expenses, and vehicle, under a separate agreement. The position will begin as outlined in the separate agreement, concurrent with the initiation of the Fish Health provisions of the Settlement's Fish Passage Plan, for selection of brood stock and passage of gametes, juvenile, and fry to upper basin tributaries. This position may be subject to renewal for additional years beyond the first five years of the Final Phase of the Settlement's Fish Passage Plan as outlined in the separate agreement. The purpose of this position is to provide biological consultation, implementation, and oversight of monitoring and evaluation activities as protection, mitigation, and enhancement programs are implemented under the new FERC license. The Licensees will consult with ODFW through designated staff and the CTWS DNR; and will coordinate with other members of the FC regarding the transfer, disposition, and care of eggs, fry, and juveniles to appropriate water bodies above the Project during the Interim Phase of the Settlement's Fish Passage Plan. In the Final Phase of the Settlement's Fish Passage Plan, the Licensees will consult with ODFW through designated staff and the CTWS DNR; and will coordinate with other members of the FC regarding the allocation of fish numbers and species for fish passage and hatchery broodstock.

13. <u>Fish Health Provisions of the Settlement's Fish Passage Plan</u>

The Licensees shall provide all funding necessary to implement the Fish Health Management Program of the Settlement Agreement's Fish Passage Plan. In addition, the Licensees shall provide all the funding necessary for the fish health management of the Hatchery pursuant to the AOP and Budget. To the extent the Fish Health provisions of the Settlement's Fish Passage Plan affects operation of the Hatchery, Hatchery operations will be coordinated with ODFW Fish Health staff. Sampling of fish for disease assessment will be undertaken by ODFW Hatchery staff, under the supervision of an ODFW fish health specialist.

14. <u>Ladder Rearing Program</u>

As of the Effective Date of this Agreement, selected cells of the Pelton fish ladder are being used as rearing ponds for spring Chinook, both for fish that are a part of the Licensees' mitigation obligations related to the Project and as a component of the Bonneville Power Administration's Hood River Supplementation Program.

The Licensees agree to maintain these selected fish ladder cells as rearing ponds (grow out facilities) as an extension of the Hatchery so long as volitional passage is not reestablished at the Project. With regard to the fish ladder cells being used for the Hood River Supplementation Program, the Licensees shall continue this program, so long as sufficient Bonneville Power Administration funds are provided for this component of the Hood River Supplementation Program, and so long as volitional upstream passage is not reestablished at the Project.

Unless otherwise agreed to in writing between the Parties, with regard to the spring Chinook rearing associated with the Project, the Licensees shall continue this component of the Hatchery program unless and until upstream volitional passage is reestablished. In that event, the Licensees will consult with ODFW, NOAA Fisheries, and the U.S. Fish and Wildlife Service regarding the future of the ladder rearing program and proposed solutions.

15. <u>Commercial Lease</u>

a. Commercial Lease. As part consideration for this Agreement, the Licensees hereby lease to ODFW, for the Term of this Agreement, three (3) primary buildings and associated auxiliary buildings and the surrounding property more particularly described in Exhibit "A" attached hereto and by this reference incorporated herein (the "Premises"). ODFW may use the Premises in accordance with the terms of this Agreement and applicable law and for no other purpose. ODFW may lease all or a portion of the Premises to ODFW employees and their immediate families as a component of the ODFW employee's employment at the Hatchery ("Employee Tenants") and to no others. If ODFW leases the Premises to its Employee Tenants, ODFW shall at all times maintain a written residential rental agreement (in a form and substance reasonably acceptable to the Licensees) between ODFW and Employee Tenants with respect to the specific building or buildings leased and any additional compliance requirements. ODFW shall apply all rents collected from Employee Tenants as a credit to the Hatchery budget. Licensees acknowledge and agree that they have reviewed the ODFW Employee Residential Rental Agreement (the "ODFW Rental Agreement"), attached hereto as Exhibit "B" and incorporated herein by this reference, and that the ODFW Rental Agreement is acceptable to Licensees. Notwithstanding the above ODFW may, from time to time and without the consent or approval of Licensee, make modifications to the ODFW Rental Agreement to the extent necessary for ODFW to remain in compliance with applicable ORS, OAR or collective bargaining agreements. However, ODFW shall promptly provide Licensees with copies of any such modified ODFW Rental Agreements for their records. If in Licensees' reasonable opinion such modified ODFW Rental Agreements materially impact Licensees rights and obligations under this Agreement, then Licensees shall give ODFW notice and the Parties shall attempt in good faith to resolve the matter by negotiations. If the Parties have not satisfactorily resolved the matter, within thirty (30) days of Licensees notice, then ODFW may revert to the prior ODFW Rental Agreements accepted by Licensees, but if ODFW opts not to so revert, then at Licensees option and upon one hundred and twenty (120) days notice to ODFW, Licensees may terminate this Commercial Lease, without terminating the balance of this Agreement. The Parties further acknowledge and agree that this lease is a commercial lease between Licensees and ODFW and under no circumstances shall the Licensees be held out as or deemed to be a residential Landlord with respect to ODFW's Employee Tenants and/or their immediate families. ODFW agrees that it shall use reasonable best efforts to: (1) enforce the ODFW Rental Agreement: and (2) provide written notice to Licenses of any material violation of the ODFW Rental Agreement that ODFW is aware of.

b. Maintenance & Repairs. Except as otherwise provided herein, the Licensees shall be responsible for maintaining the Premises in a habitable condition and for making repairs necessary to the integrity of the Premises, subject to reasonable notice thereof by ODFW. Needed repairs and maintenance items shall be reported in writing to the Licensees' Project Manager, who shall promptly arrange to have the repairs made. Any repair or improvement necessitated by a health and safety issue or hazardous situation may be completed by Licensees' Project staff or by a licensed and bonded contractor in accordance with all applicable laws and regulations. In the event of an emergency repair that must be made outside of normal Project business hours, ODFW may arrange to have such emergency repair made by other than the Licensees' Project staff, utilizing only a licensed and bonded contractor, and shall be reimbursed by Licensee for any reasonable emergency repair expenditure. As soon as possible following the emergency, ODFW shall report back to Licensees with documentation justifying all emergency repair expenses. Emergency repairs are those that threaten the integrity of the Premises or that impair the immediate safety, health or welfare of ODFW or its Employee Tenants.

1. Except in the event of an emergency, capital improvements and additions to the Premises shall not be made outside of the annual capital project review process. Unless specifically agreed to, in advance, by the Licensees' Project Manager, no funds budgeted for other Hatchery purposes shall be used to repair, upgrade, or alter the Premises.
2. The Licensees shall notify and consult with the Hatchery manager or other authorized ODFW contact person to determine a schedule to enter and inspect the Premises, to make necessary repairs, alterations, or additions thereto, and for other reasonable purposes. In emergencies, the Licensees have the right to enter the Premises; however, attempts shall be made to notify ODFW prior to entry.

3. The Parties are not currently aware of any code violations with respect to the Premises and, except as specifically set forth herein, the Licensees have not made any promise to alter, remodel, repair or improve the Premises. Notwithstanding the foregoing, Licensees shall ensure that the Premises comply with all applicable laws and regulatory and building code requirements for commercial occupancy by ODFW or its Employee Tenants.
4. Licensees shall provide water and electricity to the Premises at all times. Licensees shall take all reasonable steps to correct any interruption of services and utilities caused by defects within Licensees' reasonable control. Electrical service shall be 110 volts. ODFW shall provide for its own surge protection for power furnished to the Premises. ODFW shall cooperate with Licensees and any utility service providers and shall allow Licensees and such providers reasonable access to pipes, lines, wiring and any other machinery within the Premises. Except as provided elsewhere herein, ODFW shall not engage any other utility services contractor without prior written approval from Licensees.
5. If the Premises or improvements thereon are damaged or destroyed by fire or other casualty to such a degree that ODFW reasonably determines that the Premises are unsuitable for the purpose leased, and if repairs cannot reasonably be made within ninety (90) days, the Licensees or ODFW may elect to terminate this lease, without terminating the balance of this Agreement. Licensees shall in all cases, within a reasonable period of time repair the damage or ascertain whether repairs can be made within ninety (90) days, and shall promptly notify ODFW of the estimated time required to complete the necessary repairs or reconstruction.

c. Quiet Enjoyment/Use. ODFW shall enjoy the rights granted by this lease free from rightful interference by any third party lawfully claiming by or through Licensee. ODFW's possession of the Premises will be free of other tenants and of conflicting claims, save and except those caused by ODFW or by persons claiming through ODFW. ODFW shall not do or permit anything to be done in or about the Premises or bring or keep anything therein that will (a) significantly increase the rate of or negatively affect any fire or other insurance the Licensees may maintain upon the Premises or any of its contents or cause cancellation of any third party insurance policy covering the Premises or any part thereof, (b) in any way obstruct or interfere with the rights of the Licensees (c) result in an immoral, dangerous, or unlawful use (including without limitation the discharging of firearms or igniting of any fireworks), (d) result in waste and/or constitute a nuisance in, on or about the Premises, (e) constitute waste in or upon the Premises, (f) in any manner or for any purpose be deemed a threat to national or homeland security by the Oregon Office of Safety and Security/Homeland Security or the US Department of Homeland Security and/or any other State or Federal security agency, or (g) constitute a violation of any applicable federal, state or municipal law, ordinance or any regulation, ordinance, order or directive of a governmental agency. ODFW shall not allow the Premises to be occupied by any person or entity known to ODFW to be listed on the US Treasury's Office of Foreign Assets Control ("OFAC") Specially Designated Nationals and Blocked Persons ("SDN") List. ODFW may apply general use pesticides or herbicides in or in the vicinity of the Premises, provided that the application is in accord with applicable law, including ORS Chapter 634, and provided however, machine-powered equipment may not be used. Garbage shall be kept in sanitary containers and removed regularly. Abandoned vehicles or appliances are not permitted in the yards of Premises.

d. ODFW shall not permit any use that causes damage or excessive or unreasonable wear and tear, or excess traffic of any kind to the Premises. Personal businesses such as bookkeeping, computer work (e.g., web design), and fly tying shall be permitted, provided, however that prior to commencing any business on the Premises, ODFW shall ensure that the Employee Tenant obtain and maintain (and provide proof of) business and general liability insurance in a minimum amount of two hundred fifty ($250,000) dollars which insurance shall name the Licensees as additional insureds. Advertising on the Premises is not allowed; however, advertising in newspaper, radio, or Yellow Pages of allowed personal businesses is permitted.

e. Exculpation/Waiver of Subrogation. The Licensees are not responsible for damage to ODFW property or the property of any Employee Tenant or occupant. Neither Licensees nor ODFW shall be liable to the other for any loss arising out of damage to or destruction of the Premises or the contents thereof, when such loss is caused by any of the perils which are or could be included within or insured against by a standard form of fire insurance with extended coverage, including sprinkler leakage insurance, if any. All such claims against one another for any and all loss, however caused, are hereby waived. Said absence of liability shall exist whether or not the damage or destruction is caused by the negligence of either Licensees or ODFW or by any of their respective agents, servants or employees. Each party shall fully provide its own property damage insurance protection at its own expense, each party shall look to its respective insurance carriers for reimbursement of any such loss, and no insurance carrier shall be entitled to subrogation under any circumstance.

f. Commercial Lease Assignment. Except as provided for herein, ODFW shall not assign all or any portion of any leasehold interest in the Premises, or encumber or pledge all or any portion of the leasehold estate, without the express prior written consent of the Licensees in each and every instance, which consent may be withheld or issued subject to conditions, in the sole discretion of Licensees. Any assignment, encumbrance, pledge, or sublease without the prior written consent of the Licensees shall be void and shall constitute a default hereunder.

g. Statement of Self-Insurance. ODFW is self-insured for its property and liability exposures, within the limits of and as subject to the Oregon Tort Claims Act, ORS 30.260 through 30.300. A Certificate of Self-Insurance will be provided, upon request of Licensees.

h. Lease Authority. The Parties mutually understand and agree that this lease is made by ODFW in its official capacity as a state agency and not by any officer or employee as an individual.

16. Permits

a. For the duration of this Agreement, the Licensees shall be responsible for obtaining, maintaining and complying with all NPDES permits. ODFW as operator of the Hatchery shall familiarize itself with the NPDES permits and shall not engage in activities resulting in NPDES permit violation, and provided, however and to the extent a permit violation is caused by the negligent or willful acts of ODFW, and following final adjudication or entry of a nonappealable decision by a court of competent jurisdiction, or both, ODFW shall reimburse PGE for any fines imposed. Notwithstanding the above, ODFW shall not be liable to Licensees for violations of NPDES permit conditions arising from the need to modify physical Hatchery facilities. When such needs for modification arise, OFDW will consult with Licensees to identify Hatchery facility limitations or the modifications to those facilities or other specific Hatchery operations required in order to ensure compliance with NPDES permit conditions.

b. The Licensees shall be responsible for obtaining and maintaining a Public Pesticide Applicator License and shall be responsible for pesticide and herbicide application at the Hatchery. In no event shall ODFW hatchery personnel apply pesticides or herbicides at the Hatchery, except as provided in §15.c.

17. Reports, Records and Inspections

a. On or before March 31st of each year, ODFW shall provide the Licensees an annual status report including:

1. A summary of pertinent Hatchery operating statistics from the previous year;
2. A comparison of actual Hatchery production figures with projected production goals;
3. A comparison of actual Hatchery costs with projected costs; and
4. A listing of all Hatchery equipment and property acquired by ODFW during the year.

b. ODFW shall use generally accepted accounting procedures to provide accurate and timely recording of receipts, by source, of expenditures made. ODFW shall establish controls adequate to ensure that expenditures charged to activities under the AOP are for allowable purposes and that documentation is readily available to verify that such charges are accurate.

c. The Licensees may:

1. Inspect Hatchery operations, facilities, and equipment at all reasonable times;
2. Subject to ORS 192.410 through 192.505 (collectively the "Oregon Public Records Law"), inspect and obtain copies of all records (excluding ODFW personnel records) relevant to ODFW's performance under this Agreement; and
3. Review the accounting methods or procedures used to document all Hatchery costs.

d. ODFW shall cooperate fully with such reviews and inspections and shall use reasonable best efforts to make all relevant records (unless otherwise exempt from review as outlined above) available for review and copying by the Licensees within a reasonable time but in any event within 30 days after receipt of a written request from Licensees to review such records. Pursuant to the Oregon Public Records Law, ODFW may charge a reasonable fee for making such relevant records available. The Licensees may, following any such review and inspection, dispute any budget expenditure by ODFW.

18. Ownership and Maintenance of Facilities

a. Except for real or personal property acquired by ODFW with non-Licensees funds or other ODFW personal property brought to the Hatchery, title to all existing or newly acquired Hatchery property, the Premises, fish facilities, and associated equipment necessary for and relating to the Project is retained by or will be in the Licensees.

b. All Hatchery facilities or parts thereof, and associated equipment, shall be maintained or replaced in accordance with prudent operating practice and approved AOPs and annual budgets. The Licensees shall be responsible for maintenance and replacement of all facilities associated with the Hatchery.

19. Compliance with Applicable Laws and Regulations

All activities of Licensees and ODFW personnel pursuant to this Agreement shall be undertaken in compliance with applicable federal, tribal, local and state laws and regulations.

20. Assignment

Except to the extent assignment may be required by the terms of the Pelton Round Butte Settlement Agreement between PGE and the CTWS dated April 12, 2000, this Agreement may not be assigned without prior written approval of each party, and all terms, restrictions, and conditions of this Agreement shall be fully binding on any successor or approved assign.

21. Modification of Agreement

This Agreement may be amended, modified, or supplemented only by a written amendment signed by Licensees and ODFW and that has been reviewed and approved by Oregon Department of Justice and the Oregon Department of Administrative Services, as required by applicable law. No amendment shall be effective until all requisite signatures and approvals have been obtained.

22. Termination

As outlined below and elsewhere herein, either party may terminate this Agreement effective upon delivery of written notice to the other party, or at such later date as may be specified if applicable federal, state, or tribal regulations or guidelines are modified, changed, or interpreted in such a way that the provisions are no longer allowable or appropriate under this Agreement. In addition, ODFW may: (1) at its sole discretion, terminate this Agreement, in whole or in part upon one hundred twenty (120) days prior written notice to Licensees; (2) terminate this Agreement immediately upon prior written notice if ODFW fails to receive funding, appropriations, limitations, allotments, or other expenditure authority as contemplated by ODFW's budget or spending plan and ODFW determines, in its reasonable administrative discretion, that it is necessary to terminate this Agreement; or (3) terminate this Agreement immediately if the Parties fail to reach agreement on an annual budget, an AOP or a material change to either. Upon the termination of this Agreement as provided herein, the Licensees may perform or retain any third party of their choice to perform the services previously provided hereunder by ODFW. The Parties acknowledge that in the event ODFW is no longer the operator of the Hatchery, any subsequent operator of the Hatchery would be subject to the then effective statutes, rules and regulations governing the operation of a private hatchery.

23. NO CONSEQUENTIAL, PUNITIVE OR EXPLEMPLARY DAMAGES

A PARTY'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS (EXCEPT TO THE EXTENT INCLUDED IN DIRECT DAMAGES) OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

24. Available Funds

Notwithstanding language in this Agreement to the contrary, obligations of ODFW under this Agreement shall not constitute an indebtedness of the State of Oregon or a pledge or lending of credit thereof, within the meaning of any constitutional or statutory limitation and do not constitute nor give rise to a pecuniary liability of the State or a right to enforce payment against any property of the State. Any such obligations of ODFW under this Agreement are payable solely from ODFW's available funds. ODFW shall not be obliged to make payment unless, at the time payment is required, ODFW has: (i) received from the Oregon Legislative Assembly appropriations, limitations or other expenditure authority, and (ii) received allotments pursuant to ORS Chapter 291, sufficient to allow ODFW, in the exercise of its reasonable administrative discretion, to pay the amounts hereunder.

25. Rights Cumulative

All rights and remedies of the Parties provided in this Agreement shall not be exclusive and are in addition to any other right and remedy provided by law.

26. Force Majeure

Neither party shall be liable to the other for any failure or delay of performance of any obligations hereunder when such failure or delay shall have been wholly or principally caused by acts or events beyond its reasonable control and without its fault or negligence, including without limitation, acts of God, terrorism, strikes, lockouts, riots, acts of war, epidemics, governmental regulations superimposed after the fact, fire, communication line failures, power failures, earthquakes, floods or other natural disasters ("Force Majeure Events"). Delays in performance due to Force Majeure Events shall automatically extend any applicable dates for a period equal to the duration of such events. In the event such nonperformance continues for a period of 60 days or more, either party may terminate this Agreement by providing written notice thereof to the other party.

27. Successors and Assigns

The provisions of this Agreement shall be binding upon and shall inure to the benefit of the Parties hereto and their respective successors and permitted assigns, if any.

28. No Third-Party Beneficiaries

Licensees and ODFW are the only Parties to this Agreement and are the only Parties entitled to enforce its terms. Nothing in this Agreement gives, is intended to give, or shall be construed to give or provide any benefit or right, whether directly, indirectly, or otherwise, to third persons unless such third persons are individually identified by name herein and expressly described as intended beneficiaries of the terms of this Agreement.

29. Notices

Except as otherwise expressly provided in this Agreement, notices to be given hereunder shall be given in writing by personal delivery of, facsimile transmission of, or mailing the same, postage prepaid, to Licensees or ODFW at the address or number set forth on the signature page of this Agreement or to such other addresses or numbers as the party may hereafter indicate pursuant to this section. Any communication or notice so addressed and mailed shall be deemed to be given five (5) calendar days after mailing. Any communication or notice delivered by facsimile shall be deemed to be given when the transmitting machine generates receipt of the transmission. To be effective against either party, such facsimile transmission must be confirmed by telephone notice to the receiving party. Any communication or notice by personal delivery shall be deemed to be given when actually received by an authorized representative of the party to whom it is addressed.

30. Severability

The Parties agree that if any term or provision of this Agreement is declared by a court of competent jurisdiction to be illegal, unenforceable or in conflict with any law, the validity of the remaining terms and provisions shall not be affected, and the rights and obligations of the Parties shall be construed and enforced as if this Agreement did not contain the particular term or provision held to be invalid.

31. Waiver

The failure of a party to enforce any provision of this Agreement or the waiver of any violation or nonperformance of this Agreement in one instance shall not constitute a waiver of that or any other provision nor shall it be deemed to be a waiver of any subsequent violation or nonperformance. No waiver, consent, modification, or change of terms of this Agreement shall bind either party unless in writing and signed by both Parties and all necessary State of Oregon approvals have been obtained. Such waiver, consent, modification, or change, if made, shall be effective only in the specific instance and for the specific purpose given.

32. <u>Headings</u>

The headings in this Agreement are included only for convenience and shall not control or affect the meaning or construction of this Agreement.

33. <u>Integration</u>

This Agreement and attached Exhibits constitute the entire agreement between the Parties on the subject matter hereof. There are no understandings, agreements or representations (oral or written) between the Parties, not specified herein regarding the subject matter of this Agreement.

34. <u>No Partnership</u>

ODFW is performing all services under this Agreement as an independent contractor. The obligations of the Parties hereunder are several and not joint. This Agreement is not intended, and shall not be construed, to create a partnership or joint venture between Licensees and ODFW. Nothing in this Agreement shall be construed to make Licensees and ODFW partners or joint venture participants.

35. <u>Good Faith</u>

In the exercise of rights and the performance of obligations hereunder, and wherever in this Agreement the consent or approval is required of either party, Licensees and ODFW shall each act in good faith. Notwithstanding the previous sentence, the Parties recognize that in managing their respective obligations hereunder, the exercise of judgment and discretion is necessary, and there shall be a strong presumption that the actions taken by each party are reasonable and taken in good faith.

36. <u>Insurance</u>

Each party shall at all times maintain sufficient insurance to cover any claim or liability which may result from any obligation of such party pursuant to or in any way associated with this Agreement. Upon the request of one party, the other party agrees to provide evidence of insurance which may be evidenced by a certificate of self-insurance.

37. <u>Tax Certification</u>

By signature on this Agreement, the undersigned hereby certifies, under penalty of perjury that the undersigned is authorized to act on behalf of PGE and that PGE is, to the best of the undersigned's knowledge, not in violation of any Oregon Tax Laws. For purposes of this certification, "Oregon Tax Laws" means a state tax imposed by ORS 401.792 to 401.816 and ORS chapters 118, 314, 316, 317, 318, 320, 321 and 323; the elderly rental assistance program under ORS 310.630 to 310.706; and local taxes administered by the Department of Revenue under ORS 305.620.

38. Confidentiality

a. Confidential Information. Subject to subsection c below, each party agrees to make reasonable efforts to maintain the confidentiality of any Confidential Information received from the other party and shall not use such Confidential Information except in performing its obligations under this Agreement. For purposes of this section 38 Confidential Information means information marked or designated in writing by a party as "confidential" prior to initial disclosure to the other party.

b. Exceptions. The confidentiality obligations imposed by this section shall not apply to: (a) information that becomes part of the public domain through lawful means and without breach of any confidentiality obligation by the recipient; (b) information subsequently and rightfully received from third parties who have the the necessary rights to transfer said information without any obligation of confidentiality; (c) information that was known to the recipient prior to receipt from the disclosing party; (d) information that is independently developed by recipient and documented in writing without use of or reference to any Confidential Information of the other party; and (e) information required to be disclosed by compulsory judicial or administrative process or by law or regulation; provided, that if either party is required to disclose Confidential Information under clause (e), that party shall first give the other party notice, unless such notice is otherwise prohibited by law, and shall provide such information as may reasonably be necessary to enable the other party to take action to protect its interests.

c. Public Records Law. Licensees hereby acknowlege that any disclosures Licensees make to ODFW under this Agreement are subject to the Oregon Public Records Laws, including but not limited to ORS 192.410-192.505, and the provisions for the Custody and Maintenance of Public Records, ORS 192.005-192.170. The non-disclosure of documents or any portion of a document submitted by Licensees to ODFW may depend upon official or judicial determinations made pursuant to the Oregon Public Records Law. If ODFW receives from a third party any request under the Oregon Public Records Law for the disclosure of information designated by Licensees as "Confidential Information", ODFW shall notify Licensees within a reasonable period of time of the request, and disclosure shall only be made consistent with and to the extent allowable under law.

39. Recycling

Licensees agree that in performance of this Agreement the Licensees shall comply with the recycling laws and policies of ORS 279.555(1)(e), regarding recycled paper and other natural resources.

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the date first above written.

Licensees:
Portland General Electric Company

121 SW Salmon Street
Portland, Oregon 97204
Telephone: 503-464-7526
Fax: 503-464-2944

By: ______________________________
Julie Keil
Director Hydro Licensing and
Water Rights

The State of Oregon acting by and through the
Oregon Department of Fish and Wildlife
3406 Cherry Ave NE
Salem, OR 97303
Telephone: 503-947-6044
Fax: 503-947-6042

By: ______________________________
Name: Kris Kautz
Title: Deputy Director for Administration

Confederated Tribes of the Warm Springs
Reservation of Oregon
PO Box 960
Warm Springs, OR 97761
Telephone: 541-553-1046
Fax: 541-543-3436

By: ______________________________
Name: James A. Manion
Title: General Manager,
Warm Springs Power Enterprises

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Salem, OR 97303
Telephone: 503-947-6044
Fax: 503-947-6042

By: Kris Kautz 1/31/06
Name: Kris Kautz
Title: Deputy Director for Administration

Approved for Legal Sufficiency:
BY: Mike Dundy per 01/31/06 email
Name: Mike Dundy
Title: Assistant Attorney General

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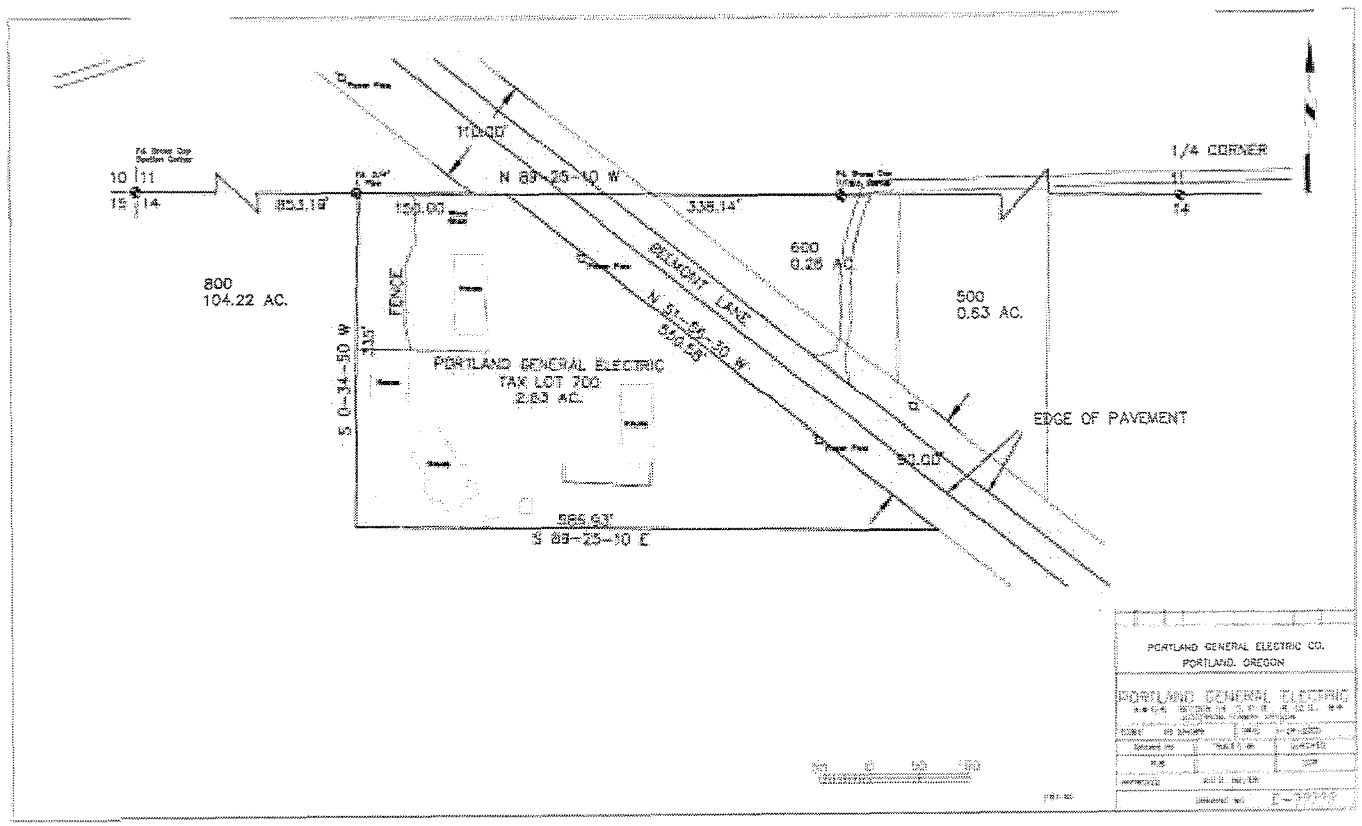
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PORTLAND GENERAL ELECTRIC CO.
PORTLAND, OREGON
PORTLAND GENERAL ELECTRIC

EMPLOYEE RESIDENTIAL RENTAL AGREEMENT

EMPLOYEE RESIDENTIAL RENTAL AGREEMENT

Date: ____________________, 20____

Landlord: **State of Oregon by and through its Department of Fish and Wildlife**

Tenant: ____

Location: ____

RECITALS:

A. Landlord consists of **Oregon Department of Fish and Wildlife** (ODFW).

B. Tenant consists of ______________________________ (Include name of all tenants)

C. Description and type of property to be rented (type of property includes but is not limited to single and multiple family dwellings, apartments, mobile homes, and mobile home pads). ODFW rents to Tenant the following described property (hereinafter called the Premises), on the terms and conditions stated below: ***(Insert type of residence, legal description, if available, street address, building number and/or unit number, and name of hatchery or wildlife area. Indicate which party is responsible for assignment of spaces, responsibility for permits if trailer, setup fees, annual inspections.)***

together with the following items of personal property owned by ODFW:

________stove ________refrigerator ________freezer

________drapes ________curtains ________microwave

________other

AGREEMENTS:

SECTION 1. OCCUPANCY

Month-to-Month

1.1 Term. The tenancy covered by this agreement is a month-to-month tenancy and may be terminated by either ODFW or Tenant at any time upon 30 days' prior written notice delivered to the other pursuant to Section 14.3 herein.

1.2 Possession. Tenant's right to possession and obligations under the Agreement commence at 12:01 a.m. on ______________, 20____, .

1.3 **Condition of Employment.** Tenant accepts housing under the following condition of employment:

☐ Mandatory condition of employment as outlined in the position description

☐ Voluntary, not as a condition of employment

SECTION 2. RENTS, UTILITIES, AND OTHER CHARGES

2.1 **Basic Rent and Other Charges**

The fair market monthly rental rate is	$____________ (1)
Percentage Reduction (See Attachment A):	$____________ (2)
The employee monthly rental rate will be:	$____________ (3) (100% minus line 2 times line 1)
Monthly Freezer Rental (optional): (Complete Attachment B)	$____________ (4)
Total (line 3 plus line 4)	$____________ (5)

Tenant will pay to ODFW as rent the sum of $____________ per month. Rent is due on the first day of each month. Rent for the first and last months of the rental term will be prorated on a daily basis if the rental commences or terminates on a day other than the first day of the month.

2.2 **Payroll Deduction**: See Attachment C.

2.3 **Utilities.** Tenant will pay the following utilities *(mark appropriate entries):*

______ electricity	______ natural gas
______ oil heating	______ water
______ air conditioning	______ sewage
______ telephone	______ garbage collection and disposal

______ and *(indicate other)* ________________________

2.4 **Rent Increases.** ODFW may increase or decrease the monthly rent at any time upon 30 days' prior written notice to Tenant.

SECTION 3. USE OF THE PREMISES

3.1 **Permitted Use.** The Premises may be used as a dwelling unit consistent with typical municipal zoning ordinances for residential areas. Business or commercial use is prohibited, except for home occupations such as artist, writer, or the other occupation that can be conveniently, unconstructively, and inoffensively pursued in a single-family dwelling. ODFW may prohibit the use of the property for home occupations when the use interferes with the conduct of state business or intrudes or otherwise causes a disturbance or nuisance to neighboring residents. No persons other than the Tenant's immediate family may reside on the Premises. For purposes of this agreement, the definition of immediate family includes parent, wife, husband, children, brother, sister, grandmother, grandfather, or another member of the immediate household and any individual designated by the Tenant as a domestic partner, so long as the designation is in writing and delivered to the Landlord before the domestic partner occupies the property.

3.2 **Pets.** Pets are permitted consistent with ODFW's Policy and Procedure ADM-16. All authorized pets must be adequately restrained and supervised so as to maintain the health and safety of the entire facility, its personnel, and the public.

3.3 **Rules and Regulations.** Tenant may not permit any acts to be done on the Premises in violation of any law or ordinance. In addition, Tenant must comply with the following rules and regulations and with any additional rules and regulations of which Tenant is hereafter given notice: *(Attach as an exhibit any rules and regulations. Tenant may have special employment obligations and duties associated with living on site. Please mark as exhibits or addendums and identify the exhibits below. All special employment obligations listed should be approved first by Human Resources.)*

3.4 **Alterations.** Tenant may not make or permit any alteration to be made on the Premises without ODFW's prior written consent.

3.5 **Restriction on Use.** In connection with the use of the Premises, Tenant must:

3.5.1 Refrain from any use that would be reasonably offensive to ODFW, other Tenants, or owners or users of adjoining Premises or would tend to create a nuisance or damage the reputation of the Premises.

3.5.2 Refrain from loading the floors beyond the point considered safe by a competent engineer or architect selected by ODFW.

3.5.3 Refrain from making any mark or perforation on or attaching any sign, insignia, antenna, aerial, or other device to the exterior walls, windows, or roof of the Premises without ODFW's written consent. Refrain from the same activities that in any way would detract from the general use of the remainder of the building and ODFW's adjacent property.

3.5.4 Refrain from any act by Tenant or by a person within Tenant's control that is outrageous in the extreme, as defined in ORS 90.400(3)(e).

SECTION 4. REPAIRS AND MAINTENANCE.

4.1 **ODFW's Responsibilities.** Except as otherwise provided in the following section, ODFW will make all structural, mechanical, and electrical repairs required to keep the Premises in good and safe order and repair in accordance with the requirements of ORS 90.320. ODFW ☐ will ☐ will not maintain the lawn and grounds of all common areas of the facility. ODFW will provide Tenant with the Lead Warning Statement (Attachment D). Any Health and Safety or hazardous item repairs or improvements will be made by licensed and bonded contractors and are subject to prior approval by ODFW. ODFW will complete the Housing Rental Inspection Form upon Tenant's occupation of the Premises and upon termination of the Agreement (Attachment E).

4.2 **Tenant's Responsibilities.** [redacted] responsible for [redacted] of the premises in good condition. Tenant must make any repairs necessitated by the negligence or willful act of Tenant or Tenant's invitees. Any Health and Safety or hazardous item repairs or improvements must be made by licensed and bonded contractors and are subject to prior approval by ODFW. Tenant agrees to notify ODFW promptly of all required repairs and consents to entry of ODFW personnel, agents, or assigns as may be required to make necessary inspections, repairs or improvements. Tenant is responsible for testing any smoke detector every six months in accordance with instructions posted on the Premises and must notify ODFW of any malfunction. Tenant has examined the Premises, accepts them in their condition as of the commencement of this Agreement, and agrees to leave them in the same condition (excepting ordinary wear and tear) at the termination of the Agreement. Tenant may inspect the [redacted] before occupation and submit to ODFW in writing any items of deferred maintenance or required repairs. Tenant will read and sign the Housing Rental Inspection Form upon Tenant's occupation of the Premises and upon termination of the Agreement (Attachment E).

4.3 **Lawn Maintenance.** If ODFW provides lawn care and maintenance, the fair market value of the service must be included in the total fair market value of the property for purposes of calculating rent.

SECTION 5. ODFW'S RIGHT OF ACCESS

Upon compliance with the requirements of this Section 5, ODFW has the reasonable right to enter the Premises in order to inspect the Premises, make necessary or agreed repairs, decorations, alterations, or improvements, supply necessary or agreed services, serve notices required or permitted under the Act, or exhibit the dwelling unit to prospective or actual purchasers, mortgagees, Tenants, workers, or contractors. Tenant may not unreasonably withhold consent for ODFW or ODFW's authorized agents to enter the dwelling unit or any portion of the Premises under Tenant's exclusive control for purposes set forth in this Section 5. ODFW may not abuse the right of access or use it to harass Tenant.

5.1 ODFW's Right to Access with Tenant's Prior Consent. Upon obtaining Tenant's prior consent, ODFW may enter the dwelling unit or any other portion of the Premises under Tenant's exclusive control for the following purposes:

(a) to inspect the Premises;

(b) to make necessary and agreed repairs, decorations, alterations, or improvements;

(c) to supply necessary, agreed-upon services; and

(d) to exhibit the dwelling unit to prospective, tenants, workers, or contractors.

5.2 ODFW Right to Access Without Tenant's Consent.

5.2.1 Except in case of emergency, agreement to the contrary or unless it is impractical to do so, ODFW will give Tenant at least 24 hours' notice of ODFW's intent to enter the Premises.

5.2.2 ODFW may enter the Premises only at reasonable times.

5.2.3 ODFW may enter the dwelling unit or Premises under Tenant's exclusive control without Tenant's consent in the following circumstances:

(a) in case of an emergency;

(b) Tenant's absence in excess of seven days if ODFW was not notified as required by this Agreement and ORS 90.340;

(c) abandonment or surrender of the Premises by Tenant as described in ORS 90.410(3); and

(d) pursuant to court order.

SECTION 6. FIRE AND THEFT INSURANCE

6.1 Fire and Theft Insurance. Tenant is not required to insure the Premises against theft, fire, or other casualty. Tenant will bear the expense of any insurance insuring the personal property of Tenant on the Premises against such risks but is not be required to insure. The State of Oregon does not insure any loss of personal property.

SECTION 7. LIABILITY TO THIRD PARTIES

7.1 **Liens.** Except with respect to activities for which ODFW is responsible, Tenant must pay as due all claims for work done on and for services rendered or material furnished to the Premises and must keep the Premises free from any liens caused by Tenant's failure to meet Tenant's obligations.

7.2 **Indemnification.** Tenant must indemnify, defend, and hold ODFW harmless from any claim, loss, or liability arising out of or related to any activity on the Premises of Tenant and any person who comes on the Premises at Tenant's invitation or with Tenant's acquiescence. Tenant's duty to indemnify does not apply to or prevent any claim by Tenant against ODFW for injury or damage to Tenant or Tenant's property for which ODFW may be liable, subject to the limitations and conditions of the Oregon Tort Claims Act, ORS 30.260 through 30.300, and the Oregon Constitution Article XI, Section 7, to the extent of liability arising out of the State's negligence.

SECTION 8. DAMAGE AND DESTRUCTION

If the Premises are damaged or destroyed by fire or other casualty, ODFW may terminate the Agreement. In lieu of terminating the Agreement, ODFW may elect, within 30 days after the damage occurs, to repair the damage and continue the Agreement. If ODFW elects to repair, ODFW has exclusive possession of so much of the Premises as may be required to effect the repairs, and Tenant is entitled to an abatement of the rent or a fair portion thereof until the Premises have been made fit for occupancy and use.

SECTION 9. EMINENT DOMAIN.

If a condemning authority takes all of the Premises or a portion sufficient to render the remaining Premises reasonably unsuitable for Tenant's use as a dwelling unit, the agreement terminates as of the date the title vests in the condemning authority. ODFW is entitled to all of the proceeds of condemnation, and Tenant has no claim against ODFW as a result of the condemnation.

SECTION 10. QUIET ENJOYMENT

ODFW warrants that it is the owner of the Premises or has a bona fide management agreement with the United States of America through its federal agencies, that ODFW has the right to rent the Premises, and that Tenant is entitled to quiet enjoyment of them during the term of the Agreement.

SECTION 11. ASSIGNMENT AND SUBAGREEMENTS

No part of the Premises may be assigned, mortgaged, or sub-rented, nor may a right of use of any portion of the property be conferred on any third person by any other means.

SECTION 12. IDENTIFICATION OF OWNER AND MANAGER

12.1 Owner. ODFW is the owner of the Premises or has a bona fide management agreement with the United States of America through its federal agencies. All service of process, notices, and demand must be made upon ODFW at the following address:

____

____

____

12.2 Manager. The person authorized to manage the Premises is ______________________ ____________. The address of the manager is:

____

____

____

Telephone: ___________________________

SECTION 13.

13.1 Basic Remedies. The remedies for breach of this Agreement include the remedies set forth in the following paragraphs.

13.2 ODFW's Right to Terminate Agreement.

13.2.1 On 24 Hours' Notice. ODFW may immediately terminate the Lease and take possession after 24 hours' written notice for any of the reasons listed in ORS 90.400(3).

13.2.2 For Nonpayment of Rent. If rent is unpaid when due and Tenant fails to pay within 10 days, after 24 hours' written notice of nonpayment and ODFW's intention to terminate the Agreement if the rent is not paid within that period, ODFW may immediately terminate the Agreement and take possession pursuant to ORS 105.105 to 105.168.

13.2.3 For Keeping a Pet. If Tenant keeps a dog, cat, or other pet capable of causing damage to persons or property on the Premises in violation of the Agreement or written approval as provided in section 3.2, ODFW may deliver a written notice to Tenant specifying the violation and stating that the Agreement will terminate on a date not less than 10 days after receipt of the notice unless Tenant removes the pet from the Premises before the date specified.

13.2.4 For Other Breaches. In the case of Tenant's material noncompliance with any other terms of the Agreement or failure to comply with the obligations contained in ORS 90.325 that materially affect health and safety, ODFW may deliver a written notice to Tenant specifying the acts and omissions constituting the breach and that the Agreement will terminate on a date not less than 30 days after receipt of notice if the breach is not remedied.

13.3 Employment as a Condition of Occupancy. If either ODFW or the tenant terminates the tenant's employment and tenant fails to leave the premises ODFW may, after 24 hours following written notice of termination of employment, evict the tenant pursuant to ORS 105.105 to 105.168.

13.4 Manner of Taking Possession. If the Agreement is terminated pursuant to the provisions of this section, ODFW may take possession in the manner provided in ORS 105.105-105.165 or in any other manner, including voluntary surrender by Tenant.

13.5 ODFW's Right to Sue for Unpaid Rent. ODFW may bring an action against Tenant at any time to recover unpaid rent. If ODFW has elected to terminate the Agreement because of Tenant's breach, ODFW may bring an action for unpaid rent for the remainder of the Agreement term.

13.6 Abandoned Property. Tenant's property left on the Premises after surrender or abandonment of the Premises or termination of this Agreement by any means will be deemed abandoned and, after proper notice as required by law, will be disposed of in accordance with ORS 90.425.

SECTION 14. MISCELLANEOUS. Waiver by either party of strict performance of any provision of this Agreement, including ODFW's acceptance of late payment of rent, is not a waiver of and does not prejudice the party's right to require strict performance of the same provision in the future or of any other provisions.

14.1 Notices.

14.1.1 Delivery of Notices. Any notice required by this Agreement must be delivered to the parties in person or by first class mail or by any service method allowed by Oregon Rules of Civil Procedure 7.

14.2 Tenant Appoints Agent. Each Tenant hereby appoints all other Tenants as that Tenant's agent to receive any notice that ODFW must give under the terms of this Agreement.

14.3 Succession. Subject to the provisions of Section 11, this Agreement is binding upon and inures to the benefit of the parties and their respective successors and permitted assigns.

14.4 Number, Gender, and Captions. As used herein, the singular includes the plural, and the plural includes the singular. The masculine and neuter each include the masculine, feminine, and neuter, as the context requires. All captions used herein are solely for convenience of reference and do not limit any of the provisions of this Agreement.

14.5 **Tenant's Acknowledgment.** Tenant hereby acknowledges that Tenant has read and received a copy of this Agreement, including any exhibits hereto.

14.6 **Prior Agreements.** This document is the entire, final, and complete agreement of the parties pertaining to the Agreement and supersedes and replaces all written and oral agreements heretofore made or existing by and between the parties or their representatives insofar as the Agreement or the rented Premises are concerned

14.7 **Modification.** No modification of this Agreement is valid unless in writing and signed by the parties hereto.

This Employee Residential Rental Agreement is effective on the date first written above.

ODFW (OR ODFW'S AGENT): ______________________________
Signature Date

____
Print or Type Name

____
Position or Title

TENANT: ______________________________
Signature Date

This Agreement with all attachments is made in duplicate
One original to ODFW
One original to Tenant
One copy to Manager
One copy to ODFW's Accounts Receivables/ASD

ATTACHMENT A

RENT REDUCTION SCHEDULE

AUTHORITY: OAR 125-060-0000

AGENCY NEED (Check one)

- ☐ 50% Condition of Employment
- ☐ 20% Not required but advantage in emergency
- ☐ 10% Not required but advantage to reduce vandalism
- ☐ 0% No need

INVASION OF PRIVACY (Check one)

- ☐ 30% Invited, used for business
- ☐ 20% Not invited but often occurs
- ☐ 10% Occasional or seasonal with restrictions
- ☐ 0% None

ISOLATION (Check one)

- ☐ 20% Extreme, more than 50 miles from full service community
- ☐ 15% Significant, 30-50 miles
- ☐ 10% Moderate, 10-30 miles
- ☐ 0% None (within 10 miles)

UNIQUE CONDITIONS

- ☐ 0-20% ____________% due to ______________________________________

____
____
____
____

Total Rent Reduction Percentage ____________%
(Insert in ODFW Rental Agreement at Section 2.1)

OREGON

ATTACHMENT B
ODFW FREEZER RENTAL AGREEMENT

I,________________________________, authorize a monthly payroll deduction amount of $____________ for personal use of the ____________________ Facility freezer for the 12-month period beginning ____________________________ and ending _____________________. (Insert amount in ODFW Rental Agreement at Section 2.1).

I will be leasing __________ cubic feet of freezer space for my personal use.

The terms of this agreement include:

- ODFW assumes no liability for loss, theft, or spoilage
- This is a 12-month agreement subject to termination under the following conditions:
  - The employee leaves employment for any reason or is transferred to another location
  - The freezer is no longer in operation for ODFW purposes
  - Space is needed for ODFW fish food and or other supplies
- Personal items must be stored in an organized manner at all times
- Personal items must be identified with the employee's name
- Space allocated for personal use will be determined by the Facility Manager
- Space will be available on a first-come first-served basis
- Use of freezer space only

Employee	**Date**	**Facility Manager**	**Date**

Formula for determining monthly rate:

Height (in inches) x width (in inches) x depth (in inches) divided by 1,728 inches = number of Cubic Feet
Cubic feet x $0.85 (comparable market rate) = monthly rate

The comparable market rate may be reviewed and adjusted as needed.

Original to Payroll
Copy to Employee
Copy to Facility file

ATTACHMENT C

Payroll Deduction Authorization
for Oregon Department of Fish and Wildlife Housing

________ I authorize the Oregon Department of Fish and Wildlife (ODFW) to deduct the rental amount for the house that I have been assigned from my monthly paycheck

OR

________ I will pay rent by personal check due by the 1st of each month following the month for which rent is due for the house that I have been assigned. Please indicate on the subject line the month for which you are paying."

I understand that this authorization will remain valid until I am no longer residing in ODFW housing or until I submit a new authorization form.

For Payroll Deduction:

I understand that I will be notified in writing of any changes in the rental amount based on the annual appraisal. If I move to other ODFW housing, I understand the rent amount will change accordingly. I understand that the rental amount will be adjusted automatically and will be deducted from my paycheck.

I understand that the rent for ODFW housing is paid at the end of each month of residence, not the first of the month. For example, October rent is deducted from the October paycheck received on November 1st.

The facility at which I currently reside is:

____

Amount $__________________/month Effective Date ______________

Employee Signature ____________________________________Date ____________

Print Name__________________________________ SSN ____________________

Return to Payroll, Attn: Kathryn Hicks, Headquarters, 503/947-6179

Copy to Employee
Copy to Manager
Copy to Facility File

Date received in:
__________Payroll
__________Rent Administrator
__________Cashier

ATTACHMENT D

LEAD WARNING STATEMENT

Housing built before 1978 may contain lead-based paint. Lead from paint, paint chips, and dust can pose health hazards if not managed properly. Lead exposure is especially harmful to young children and pregnant women. Before renting pre-1978 housing, Landlords must disclose the presence of known lead-based paint and/or lead-based paint hazards in the dwelling. See 42 USC Sec. 4852d. Tenants must also receive a federally approved pamphlet on lead poisoning prevention. In the following, the term "Landlord" includes their agents and representatives.

Landlord's Disclosure:

A. Presence of lead-based paint or lead-based paint hazards (check one)

☐ Known lead-based paint and /or lead-based paint hazards are present in the housing (explain) ________
____
____
____

☐ Landlord has no knowledge of lead-based paint and/or lead-based paint hazards in the housing.

B. Records and reports available to the tenant (check one)

☐ Landlord has provided the Tenant with all available records and reports pertaining to lead-based paint and/or lead-based paint hazards in the house (list documents) ____________________
____
____
______

☐ Landlord has no reports or records pertaining to lead-based paint and/or lead-based paint hazards in the housing.

Landlord or Manager's Initials: ____________

Tenant's Acknowledgement:

☐ Tenant has received copies of all information listed above.

☐ Tenant has received the pamphlet Protect Your Family From Lead in Your Home.

Tenant's Initials: ____________

Certification of Accuracy

The following parties have reviewed the information above and certify to the best of their knowledge that the information provided by the signatory is true and accurate.

________________________ Landlord	________________________ Date
________________________ Tenant	________________________ Date

Original to Landlord/file
Copy to Tenant
Copy to Facility File

Attachment E

Oregon Department of Fish and Wildlife Housing Rental Inspection Form

Facility ____________________ Inspected By: ____________________

Property # ____________________

Resident ____________________

Interior					Condition	
Attic					Specify repair needed:	
Item	Type	No.	In need of repair		Move in:	Move Out:
Insulation			Yes	No		
Vents			Yes	No		
Chimney			Yes	No		
Bathroom Vent			Yes	No		

Comments: ____________________

Kitchen					Specify repair needed:	
Item	Type	No.	In need of repair		Move in:	Move Out:
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Cabinets (Paint/Stain)			Yes	No		
Sink			Yes	No		
Range Vent (Light/Fan)			Yes	No		
Floor (Carpet/Linoleum/Other)			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
Smoke Alarms			Yes	No		
			Yes	No		
			Yes	No		
			Yes	No		

Comments: ____________________

Attachment E

Interior					Condition	
Living Room					**Specify repair needed:**	
Item	**Type**	**No.**	**In need of repair**		**Move In:**	**Move Out:**
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Cabinets (Paint/Stain)			Yes	No		
Floor (Carpet/Linoleum/Other)			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
Smoke Alarms			Yes	No		
			Yes	No		
			Yes	No		

Comments: ______________________________

Dining					**Specify repair needed:**	
Item	**Type**	**No.**	**In need of repair**		**Move In:**	**Move Out:**
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Cabinets (Paint/Stain)			Yes	No		
Floor (Carpet/Linoleum/Other)			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
Smoke Alarms			Yes	No		
			Yes	No		
			Yes	No		

Comments: ______________________________

Attachment E

Interior					Condition	
Bedroom # 1					**Specify repair needed:**	
Item	**Type**	**No.**	**In need of repair**		**Move In:**	**Move Out:**
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Closet			Yes	No		
Floor (Carpet/Linoleum/Other)			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
Smoke Alarms			Yes	No		
			Yes	No		
			Yes	No		

Comments: ______________________________

Bedroom # 2					**Specify repair needed:**	
Item	**Type**	**No.**	**In need of repair**		**Move In:**	**Move Out:**
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Closet			Yes	No		
Floor (Carpet/Linoleum/Other)			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
Smoke Alarms			Yes	No		
			Yes	No		
			Yes	No		

Comments: ______________________________

Attachment E

Interior					Condition	
Bedroom # 3					Specify repair needed:	
Item	Type	No.	In need of repair		Move in:	Move Out:
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Closet			Yes	No		
Floor (Carpet/Linoleum/Other)			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
Smoke Alarms			Yes	No		
			Yes	No		
			Yes	No		

Comments: ______________________

Bathroom #1					Specify repair needed:	
Item	Type	No.	In need of repair		Move in:	Move Out:
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Cabinets (Paint/Stain)			Yes	No		
Sink			Yes	No		
Bathroom Fan			Yes	No		
Floor (Linoleum/Other)			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
Smoke Alarms			Yes	No		
Tub/Shower			Yes	No		
Toilet			Yes	No		
			Yes	No		

Comments: ______________________

Attachment E

Interior			Condition			
Bathroom # 2					Specify repair needed:	
Item	Type	No.	In need of repair		Move In:	Move Out:
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Cabinets (Paint/Stain)			Yes	No		
Sink			Yes	No		
Bathroom Fan			Yes	No		
Floor (Linoleum/Wood/Other)			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
Smoke Alarms			Yes	No		
Tub/Shower			Yes	No		
Toilet			Yes	No		

Comments: ______________________________

Basement					Specify repair needed:	
Item	Type	No.	In need of repair		Move In:	Move Out:
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Cabinets (Paint/Stain)			Yes	No		
Sink			Yes	No		
Dryer Vent Hose			Yes	No		
Floor (Carpet/Linoleum/Other)			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
Smoke Alarms			Yes	No		
			Yes	No		
			Yes	No		

Comments: ______________________________

c. Within 30 days of receipt of ODFW's proposed AOP, the Licensees and ODFW shall meet to approve or propose revisions to the AOP. ODFW and the Licensees shall attempt to negotiate a resolution to any disputed portions of the AOP. Both Parties shall seek to approve a final AOP by June 15. If the Parties cannot reach agreement on a portion of the AOP for a year and that AOP year commences then the remainder of the AOP shall take effect. If excluding the disputed portion of the AOP makes Hatchery operation impractical under such AOP, then the Parties shall operate the Hatchery in accordance with the AOP for the most recent preceding year until the dispute is resolved.

d. ODFW must receive written approval from the Licensees' lead fish biologist at the Project for significant changes to an approved AOP, including material changes in Hatchery activities. ODFW shall request approval as soon as is practicable after the need for such change becomes known. ODFW shall include with such request documentation adequate to justify the requested changes, including requested capital improvements or acquisition of materials, equipment, or supplies.

e. Notwithstanding the above, in the event of an emergency at the Hatchery, ODFW shall notify Licensees' lead fish biologist who has the authority to authorize emergency expenditures. If the Licensees' lead fish biologist is unavailable, ODFW shall notify the Licensees' alternate authorized personnel who will be identified by Licensees at each annual meeting. However, in the event ODFW can not reach Licensees' alternate authorized personnel, ODFW may make such repairs as are necessary to deal with any such emergency and shall be reimbursed by Licensees for any reasonable emergency expenditure. As soon as possible following the emergency, ODFW shall report back to Licensees with documentation justifying all emergency expenses.

6. Approval of Budget and AOP

Upon approval by the Parties, the annual budget and the AOP shall be signed by authorized representatives of the Licensees and ODFW. The Parties acknowledge and agree that it is their intent to be bound by the annual budget and AOP documents, which documents, upon execution, are deemed to be incorporated herein and become part of this Agreement. The first budget and AOP documents shall be effective as of July 1, 2006.

7. Meetings

The Parties shall meet twice each calendar year to review: (1) the operation and maintenance of the Hatchery, (2) the status of the AOP, the annual budget and the biennial budget, and (3) any other topics as may be mutually agreed. One meeting will be held in conjunction with the annual meeting required under the Settlement's Fish Passage Plan. The other meeting will be held on or before May 15 of each year.

8. Hatchery Production Goals

The Parties agree that the existing Hatchery facilities are appropriate for raising spring Chinook and steelhead at the following agreed- upon levels:

Attachment E

Interior					Condition	
Utility Room					**Specify repair needed:**	
Item	Type	No.	In need of repair		Move In:	Move Out:
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Cabinets (Paint/Stain)			Yes	No		
Sink			Yes	No		
Floor (Linoleum/Other)			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
Smoke Alarms			Yes	No		
Dryer Vent & Hose			Yes	No		
			Yes	No		
			Yes	No		

Comments: ____________________

Heating					**Specify repair needed:**	
Item	Type	No.	In need of repair		Move In:	Move Out:
Furnace (Oil/Gas)			Yes	No		
Heat Pump			Yes	No		
Woodstove (Wood/Pellet)			Yes	No		
Electric Baseboard			Yes	No		
			Yes	No		
			Yes	No		

Comments: ____________________

Attachment E

Exterior — **Condition**

Roof — Specify repair needed:

Item	Type	No.	In need of repair		Move In:	Move Out:
Roof Wood Shingle/Metal/Other)			Yes	No		
Age of Roof ______________			Yes	No		
Flashing (Valley/Ridge/Vents/Chimney)			Yes	No		
Chimney			Yes	No		
Gutters			Yes	No		
Splash Blocks			Yes	No		
			Yes	No		
			Yes	No		
			Yes	No		
			Yes	No		

Comments: ____
____
____

Siding — Specify repair needed:

Item	Type	No.	In need of repair		Move In:	Move Out:
Siding (Wood/Metal/Vinyl)			Yes	No		
			Yes	No		
			Yes	No		
			Yes	No		
			Yes	No		

Comments: ____
____
____

Foundation — Specify repair needed:

Item	Type	No.	In need of repair		Move In:	Move Out:
Solid Perimeter/Post & Beam/Slab/Other			Yes	No		
Water Damage(Dry Rot/Insect Damage/Vents)			Yes	No		
			Yes	No		
			Yes	No		
			Yes	No		
			Yes	No		

Comments: ____
____
____

Attachment E

Exterior			Condition			
Garage					Specify repair needed:	
Item	Type	No.	In need of repair		Move In:	Move Out:
Garage Door			Yes	No		
Ceiling (Drywall/Tile/Plaster)			Yes	No		
Wall Surface (Drywall/Wood Panel/Plaster)			Yes	No		
Windows (Wood/Metal/Vinyl)			Yes	No		
Screens			Yes	No		
Door & Trim			Yes	No		
Cabinets (Paint/Stain)			Yes	No		
Floor			Yes	No		
Electrical Outlets (GFI/Ungrounded/Grounded)			Yes	No		
Lighting Fixtures			Yes	No		
			Yes	No		
			Yes	No		
			Yes	No		

Comments: ______

Other					Specify repair needed:	
Item	Type	No.	In need of repair		Move In:	Move Out:
			Yes	No		
			Yes	No		
			Yes	No		

Comments: ______

Sign and date checklist and keep a copy on file.

Tenant	Move In Date
Manager	Move In Date
Tenant	Move Out Date
Manager	Move Out Date

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Transmission & Distribution O&M

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bill Nicholson
Larry Bekkedahl

February 12, 2015

Table of Contents

I. Introduction

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

A. My name is Bill Nicholson. I am Senior Vice President of Customer Service, 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 PGE's 2016 test year Transmission and Distribution (T&D) operations and maintenance (O&M) costs. We discuss how they support PGE's goal of operational excellence that incorporates improvement efforts and efficiency gains.

Q. What are the T&D group's primary goals in delivering service to its customers?

A. Our primary goals are to:

- Provide safe and reliable energy delivery services to our customers;
- Deploy new techniques and process improvements to enhance efficiency and increase customer value;
- Cultivate a corporate culture that improves employee safety; and
- Ensure compliance with regulations for transmission grid reliability.

Q. What are your O&M costs for the 2016 test year?

A. In 2016, we forecast T&D O&M costs totaling $108.7 million, which represents a $1.1 million, or a 0.5% annual increase compared to 2014 actuals. Table 1, below, summarizes those costs for 2014 and 2016. As shown in Table 1, T&D direct costs decline during the period, but this decline is mostly offset by an increase in Information Technology (IT) costs.

Table 1
Summary of T&D O&M Expenses ($ Million)

	2014 Actuals	2016 Test Year	Variance 2014 - 2016	Annual Average % Increase / (Decrease)
T&D Labor	$47.1	$43.1	($4.0)	(4.4%)
T&D Non-Labor	$43.4	$39.9	($3.5)	(4.1%)
Subtotal T&D	**$90.5**	**$83.0**	**($7.5)**	**(4.2%)**
Information Technology	**$17.2**	**$25.7**	**$8.6**	**22.5%**
Total T&D O&M*	**$107.6**	**$108.7**	**$1.1**	**0.5%**

**May not sum due to rounding*

Q. Why are you comparing the 2016 test year costs to 2014 actuals?

A. We compare our forecast of 2016 test year costs to 2014 because it represents PGE's most recent year of actual results.

Q. What do the IT costs represent?

A. They represent costs that are directly assigned and allocated to T&D as they relate to PGE's efforts to develop, operate, and maintain our computer, information, cyber, and communication systems.

Q. Please explain the forecasted increase in IT costs.

A. In summary, the increase in IT costs results from the following:

- The IT deferral mechanism approved by Commission Order No. 13-459 for certain 2014 IT costs;
- Software and hardware maintenance agreements;
- Day 2 IT support for the 2020 Vision projects; and
- Labor loadings on allocated IT costs.

Because IT costs are charged or allocated to all operating areas of the company, they are discussed in detail in PGE Exhibit 600.

Q. How is the remainder of your testimony organized?

A. The remainder of our testimony is organized into the following sections:

- Section II: T&D Operations
- Section III: T&D Transformation
- Section IV: Conclusion
- Section V: Qualifications

II. Transmission & Distribution Operations

A. O&M Expenses

Q. Table 1 indicates that T&D O&M expenses (not including IT) have decreased by approximately $7.5 million from 2014 actuals to the 2016 test year. What accounts for the $7.5 million decrease?

A. The decrease is due primarily to the completion of Maximo, Mobile and Scheduling Wave 2, the Geographic Information System (GIS) and Graphic Work Design (GWD) Replacement project, the Outage Management System (OMS) Replacement project. Maximo, Mobile and Scheduling (MMS) Wave 2 came online in the fourth quarter of 2014 and GIS/GWD and OMS are expected to be online in the second and third quarters of 2015 respectively.

Q. Are there incremental O&M costs in the 2016 test year?

A. Yes. There are two primary incremental O&M increases in 2016:

- $1.8 million – Polychlorinated biphenyls (PCB) Testing; and
- $1.1 million – Tree Trimming

1. PCB testing

Q. Please describe PCB Testing.

A. PCB Testing is the first part of the overall PCB Elimination Program, a ten-year program set to meet anticipated PCB regulations and to reduce the risk of exposure to human environmental receptors. The testing portion of the program is a five-year project with testing beginning in 2016. PGE will test approximately 75,000 distribution transformers with unknown PCB content to determine their PCB content levels. All transformers ≥50 parts per million (ppm) PCBs and all those that are located in critical areas that test positive for any level of PCB will be replaced with non-PCB transformers. By first testing the transformers, PGE avoids spending in the order of $100 million in capital associated with replacing all transformers with unknown PCB levels.

Q. Why would PGE remove transformers that contain PCBs?

A. There are two primary reasons for removing these transformers.

1) The Environmental Protection Agency (EPA) issued an advanced notice of proposed rulemaking in April 2010 that would require the phase out of current transformers that have PCBs ≥50 ppm. The EPA contends that these transformers pose an unreasonable risk to the environment and must be taken out of service and properly disposed. PGE Exhibit 801 provides a copy of EPA's advance notice of proposed rulemaking on PCBs.

2) Removing PCB transformers reduces the risk of exposure to human and environmental receptors in the vicinity of such transformers that may be located throughout PGE's service territory.

Q. What is considered a critical area?

A. PGE has defined "critical areas" as those that have nexus or proximity to either waterways or sensitive human receptors. Proximity would include drainage basins to the Portland Harbor and Downtown Reach portions of the Willamette River, and the Columbia slough. Sensitive receptors are generally locations or facilities where particularly vulnerable portions of the population (e.g., young or old) may frequent. This includes schools, daycares, hospitals, and elderly care facilities.

Q. How did PGE derive the critical area for PCB transformers?

A. PGE used data from available State, Metro, and City of Portland databases, which will be augmented with other information collected during testing. PGE then used a 100-yard radius to provide general insight to waterways and sensitive receptors.

Q. How much is the PCB Elimination Program expected to cost?

A. This five-year project will cost in the order of $80 million in capital and $9 million in O&M. While the bulk of the O&M costs associated with this project relates to PCB testing, there are some O&M costs for engineering and project management associated with the replacement of equipment.

Q. How much O&M has PGE included in the 2016 test year for PCB Testing?

A. We included $1.8 million in the 2016 test year forecast for testing PCB levels in transformers.

Q. Did PGE include amounts associated with the PCB Transformer Replacement Project in its 2016 rate base for calculating the test year revenue requirement?

A. No. As noted in PGE Exhibit 200, PGE's test year rate base is set as of December 31, 2015 and does not include 2016 additions to plant.

2. Tree Trimming

Q. How did you estimate tree trimming costs for 2016?

A. The tree trimming program runs on two- or three-year cycles and is contracted on a time and materials basis. PGE first determines the number of crews necessary to complete the work to comply with the Oregon Administrative Rule (OAR) 860-024-0016 and meet PGE's service quality measures (SQMs), and then applies the labor rates for the crews to determine total costs.

For the work in 2016, we forecast a need for 36 tree trimming bucket crews, 2 sub transmission trimming crews, 3 backlot trimming crews, 2 one-person response crews, and 1 cross country right-of-way climbing/clearing crew.

Q. Comparing 2014 to 2016, is the amount of work and the number of contract crews expected to be similar?

A. Yes, assuming similar weather and temperature conditions.

Q. If they are similar, then by how much are tree trimming non-labor costs projected to increase?

A. We forecast an increase of approximately $1.1 million, which is due primarily to the higher pay rates in the new union contract; the rates account for approximately $0.8 million of the increase. In 2014, Asplundh Tree Experts and IBEW Local 125 negotiated a new three-year contract. The outcome of the negotiations was higher wages for union employees. For PGE, which uses Asplundh, the rate for a standard two-person trimming crew increased approximately 3% per year.

Q. What is PGE doing to keep contractor costs reasonable?

A. PGE bid the tree-trimming contract in 2014, and will bid the contract again in 2016, to ensure we receive competitive pricing. We also manage the contract and ensure costs are reasonable and meet required specifications. PGE has a staff of seven foresters and one forester supervisor to perform this management role.

The foresters assign the work by designating trees to be trimmed or removed and they also coordinate with customers when necessary. As trimming progresses, the foresters inspect the trimming for productivity, which is determined by actual versus estimated costs, along with adherence to clearance, arboricultural, and safety specifications.

Efforts to control costs by the foresters include activities such as ensuring the contract crews are located as close to the project as possible, thereby minimizing travel time; managing trimming debris by blowing chips back on site versus into a dump truck, thereby minimizing non-productive time spent dumping chips; requiring a project work progression plan so the crews do not have to shift job sites frequently; and requiring that the scheduling of extra resources, like flagging or equipment, is timely and efficient.

B. FTEs

Q. How does PGE expect the T&D labor force to change from 2014 to 2016?

A. As listed in Table 2, below, T&D full time equivalent employees (FTEs) are projected to increase by approximately 18.8 from 2014 to 2016. This increase is primarily driven by incremental off-shift crews, repairmen and other positions included in PGE's 2015 general rate case (UE 283). These positions are described below, and summarized in Table 2.

Table 2
Summary of T&D FTEs

Category	2014 Actuals	2016 Test Year	Variance 2014 – 2016
T&D FTEs	919.7	938.5	18.8

Q. Please explain the Off-Shift Crew and Repairmen position additions.

A. As a result of the T&D Transformation program, PGE found efficiencies of approximately $0.2 million in avoided overtime expense by adding the following to support system restoration efforts during evening hours: 1) two repairmen positions; and 2) two journeyman lineman positions, along with a non-incremental FTE to form a three-man off-shift crew. The cost of these positions will be offset from the reduction to overtime expense.

Q. The Off-Shift Crews and Repairmen make up four FTEs of the approximate nineteen FTE increase from 2014 to 2016. Please explain the remaining variance.

A. The remaining increase results from FTEs included in UE 283 and position vacancies in 2014 due to challenges in filling specialized positions. The UE 283 position additions include: 1) distribution automation engineers to support PGEs Smart Grid initiatives; 2) service inspectors and a service coordinator position to meet the demand of our growing retail customer population (e.g. new connects); and 3) transmission pre-scheduler positions to meet FERC Order No. 764, which requires transmission providers to offer intra-hourly transmission scheduling at 15-minute intervals.

C. Distribution Service Quality

Q. Does PGE provide service quality reports to the OPUC at the Distribution level?

A. Yes. PGE submits annual SQM reports, which contain outage and other results. The Commission Staff reviews our SQM reports for compliance with defined performance levels. PGE's SQM reports provide annual results of its System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI).

Q. What are SAIDI, SAIFI and MAIFI?

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.

Q. Has PGE been meeting its requirements for SAIDI, SAIFI and MAIFI?

A. Yes. As shown in Table 3 below, for 2012 through 2014, PGE's results were well within the thresholds established by the OPUC. PGE's three-year weighted averages (2012 through 2014) for all three measures also fall well below the OPUC penalty thresholds. 2014 SAIDI results were higher than previous years largely due to higher than normal storm activity and outages caused by vegetation and wildlife (e.g. squirrels).

Table 3
Three-year Weighted Averages and Penalty Threshold Limits

Year	SAIDI (minutes)	SAIFI (occurrences)	MAIFI (occurrences)
2014	93	0.7	1.3
2013	62	0.5	0.9
2012	72	0.6	1.1
3-Year Weighted Average	**76**	**0.6**	**1.1**
OPUC Level 1 Penalty Threshold	105	1.2	5.0

Q. Did PGE experience any major storms in 2014?

A. Yes. In 2014, PGE experienced three level 3 storms in the fourth quarter and a near level 3 storm in the first quarter resulting in approximately $7.3 million in storm damage costs. Of this amount, approximately $5.4 million was classified under the level 3 storm deferral.

Q. How did PGE determine these storms should be classified as level 3 storms?

A. Based on the criteria agreed upon in UE 215, PGE determined that the storms mentioned above met the criteria for a level 3 classification and that the funds collected for major storms will be used to offset 2014 costs associated with those level 3 storms.

Q. Please describe the storm deferral approved in UE 215.

A. Per OPUC Commission Order No. 10-478, parties agreed to allow PGE to collect $2 million annually (based on a rolling 10-year average of level 3 storms, adjusted to reflect present value) for use against future level 3 storm costs.

Q. Do the costs incurred from the 2014 level 3 storms exceed the funds collected to date?

A. No. Through 2014, PGE has accrued $8 million for major storm damage restoration. Of the funds collected, PGE will use $5.4 million to offset the 2014 level 3 storm damage costs, leaving a remaining balance of $2.6 million at year-end 2014.

Q. Will you be updating the 10-year rolling average through 2014 to determine the accrual rate for the storm deferral?

A. Yes. As stated earlier, PGE currently accrues $2 million each year to the storm damage restoration account for future major storm damage. Based on level 3 storms that occurred between 2005 and 2014, PGE's 10-year average for level 3 storms is approximately $2.3 million.

Q. Based on this recent experience, is PGE proposing to update its major storm accrual in this case?

A. No. Due to minimal variance between the current and updated accrual rate, PGE does not request to increase the storm deferral accrual rate at this time.

III. Transmission and Distribution Transformation

Q. In PGE's 2014 general rate case (UE 262) you introduced T&D Transformation. Please provide a brief summary of the program.

A. T&D Transformation is a subset of the 2020 Vision Program. It is a program that focuses on multiple initiatives to improve efficiency and effectiveness in the T&D area through process standardization and leveraging the software replacements within the 2020 Vision Program (see PGE Exhibit 600). As a result, PGE is implementing multiple initiatives to improve efficiency and effectiveness within T&D, with a focus on the following five areas:

- Employee Safety;
- Accountability;
- Process Standardization;
- Productivity; and
- O&M Efficiency

Q. Please describe how the T&D Transformation program is being implemented.

A. The T&D Transformation program is based upon the principles of centralization, standardization and integration processes. Operating units, where appropriate, are first centralized, work practices are standardized, then technology is integrated where possible to streamline workflow and automate processes.

Q. PGE Exhibit 600, Section III, Part B, describes the 2020 Vision projects that have been implemented and forecasted to close in 2015. Which of those impact T&D Transformation?

A. Projects that have or will impact T&D Transformation include:

- Maximo, Mobile and Scheduling Wave 1, which closed in 2012;
- Maximo, Mobile and Scheduling Wave 2, which closed in late 2014;
- Geographic Information System (GIS)/Graphic Work Design (GWD) systems, which is forecasted to close in the second quarter of 2015; and
- Outage Management System (OMS), which is forecasted to close in the third quarter of 2015.

Q. Are you implementing any new initiatives or process improvements in 2015 and 2016?

A. Yes. As mentioned above, the new GIS/GWD systems and OMS application are forecasted to be operational in 2015. Once the new systems are in place, employees will be trained on the new systems. When the systems are implemented and integrated with the other T&D enterprise systems (e.g. Maximo), T&D operations will be reevaluated and new process improvements will be developed. For example, the GWD system will change the way work is completed in PGE's Service and Design organization where roles and processes will need to be adjusted to align with the system's capabilities.

IV. Conclusion

Q. Please summarize your request for T&D in this filing.

A. We request that the Commission approve PGE's forecast of $108.7 million in T&D costs in the 2016 test year, representing a $1.1 million, or 0.5% increase compared to 2014 actuals. Not including the $25.7 million in IT costs, which are discussed in detail in PGE Exhibit 600, this represents a $7.5 million decrease from 2014 actuals and is primarily driven by the completed development and implementation of the remaining T&D 2020 Vision projects, Maximo, Mobile and Scheduling Wave 2, GIS/GWD and OMS.

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 transmission 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	EPA's Advance Notice of Proposed Rulemaking

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.

Federal Register / Vol. 75, No. 66 / Wednesday, April 7, 2010 / Proposed Rules 17659

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

Federal Register / Vol. 75, No. 66 / Wednesday, April 7, 2010 / Proposed Rules 17663

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Customer Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Kristin Stathis
Carol Dillin

February 12, 2015

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 2016 test year and compare them to 2014, which represent PGE's most recent actual results. We also discuss initiatives that support improving customer service 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' expectations; and
- Improving business processes for billing and enhanced customer channels.[3]

Q. Please describe the functions of PGE's Customer Service organization.

A. We define Customer Service functions as those that 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

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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.

requests received through 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 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 2016 costs in comparison to 2014 actual costs. In Section III, we provide an update to the Customer Engagement Transformation (CET) program, describing actual and planned progress from 2014 through 2016. In Section IV, we discuss PGE's proposed expansion of the Fee-Free Bank Card (FFBC) program. We then submit conclusions in Section V and provide our qualifications in Section VI.

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[4] Interactive Voice Response 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 price. 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 excellence. 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, 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, bi-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 we noted above, PGE has implemented projects that improve service, increase efficiency, and provide benefits and convenience to customers in how they interact with

PGE. By way of example, we implemented two improvement projects mentioned in PGE's previous general rate case, Docket No. UE 283:

- The new paperless billing program launched with greater than anticipated participation. The project included improved e-mail notifications and a new "Quick Pay" link to enable enrolled customers to pay their bill directly from their bill notification email.
- A web-enabled project launched that automated customer 'move' service requests. The project reduced processing time for this service, freeing up our employees' time to focus on customer needs rather than process. The process improvement also provides customer benefit by expediting the service request.

Over the next several years (2015 to 2018), project prioritization will focus primarily on CET work discussed further in Section III, and implementation of customer-enabled capacity initiatives identified in PGE's Smart Grid Report and Integrated Resource Plan. Customer feedback will continue 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, will be 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 2016 test year?

A. PGE forecasts approximately $72.1 million in Customer Service O&M for 2016, excluding uncollectible expenses, which are a revenue sensitive cost. This represents a $13.0 million increase relative to PGE's 2014 actual costs. The overall increase to Customer Service is attributed primarily to cost escalation, new or expanded programs, CET costs, and IT allocations. Table 1 summarizes these costs and they are discussed in more detail below.

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

Category		2014 Actuals		2016 Forecast		Delta (2016-2014)*
Labor (excluding CET)	$	28.7	$	32.6	$	3.9
Non-Labor (excluding CET)	$	15.3	$	17.4	$	2.1
Subtotal*	**$**	**44.0**	**$**	**49.9**	**$**	**6.0**
CET Costs	$	1.6	$	4.5	$	2.9
IT Costs	$	13.6	$	17.7	$	4.1
Subtotal*	**$**	**59.1**	**$**	**72.1**	**$**	**13.0**
Uncollectibles	$	6.9	$	7.9	$	1.0
Total Costs*	**$**	**66.0**	**$**	**80.0**	**$**	**14.0**
FTEs		**484.9**		**486.9**		**2.0**

* May not sum due to rounding

Q. Please explain the forecasted increase in labor costs from 2014 to 2016.

A. The increase in Customer Service labor from 2014 to 2016 is driven primarily by wage and salary escalation as described in PGE Exhibit 500. Additional sources of the increase in labor are as follows:

- An increase of two full time equivalent employees (FTEs), which is net of: 1) FTE reductions budgeted in 2015 from efficiencies derived by the CET program; and 2) FTE increases to support customer growth and corresponding increases in customer call volume, smart grid activities, emerging technologies, and data analysis.

  The change in FTEs, however, is more complicated regarding costs. Most FTE reductions in Customer Service have occurred in the hourly employee category whereas many of the incremental positions are exempt, which require more highly skilled employees. Consequently, additional labor costs result from the shift in FTE types within Customer Service.

- Four FTEs will be added in 2015 ($0.3 million in labor) but this cost is entirely offset by Other Revenue because it is funded by the Energy Trust of Oregon. On a corporate basis, this is a net zero change in revenue requirement but appears to be a cost increase for Customer Service operations and a corresponding increase in Other Revenue.

- Additional PTO loading that pertains to directly charged IT labor. Although the paid-time-off (PTO) loading for allocated IT labor is identifiable and easily separated as an IT cost, the PTO loading on directly charged IT labor is not. Consequently, when directly charged IT labor increases, as it does from 2014 to 2016 for Customer Service operations, the associated PTO loading is absorbed in Customer Service labor rather than separated and included with IT costs.

Q. What accounts for the increase in non-labor costs from 2014 to 2016?

A. The increase in non-labor is primarily due to the introduction of PGE's FFBC program. Because PGE introduced the program in late 2014, we expect a significant increase in 2015 and 2016. Therefore, we budget an increase of $0.9 million in 2015 and an additional $1.2 million in 2016 based on projected residential participation levels and the program's expansion to small non-residential customers in 2016. We discuss the FFBC program in more detail in Section IV, below. The remaining increase in non-labor costs is mainly attributable to cost escalation from 2014 to 2016.

Q. What is the nature of the CET cost increase?

A. The CET cost increase is the net effect of the deferral mechanisms approved by Commission Order Nos. 13-459[5] and 14-422[6] plus the application of similar treatment to forecasted 2016 CET costs. We describe CET and its cost impacts in Section III, below.

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[5] Docket No. UE 262, for the 2014 deferral; see Appendix A, pages 3 and 4, Issue S-7.

Q. Please explain the forecasted increase in IT costs.

A. The increase in IT costs is primarily due to the following:

- The IT deferral mechanism approved by Commission Order No. 13-459 for certain 2014 IT costs;
- Software and hardware maintenance agreements;
- Day 2 IT support for the 2020 Vision projects; and
- Labor loadings on allocated IT costs.

Because IT costs are charged or allocated to all operating areas of the company, they are discussed in detail in PGE Exhibit 600.

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[6] Docket No. UE 283, for the 2015 deferral; see Appendix B, page 2, Issue S-2.

III. Customer Engagement Transformation (CET)

Q. In PGE's two previous general rate cases (UE 262 and UE 283), you addressed the CET program. Please provide a brief summary of the program.

A. The CET program is a comprehensive multi-year program (i.e., 2014 to 2018) comprised of a set of initiatives focused on operational efficiencies, process improvements, employee development, business strategies, and the replacement of two large customer systems:

- Customer Information System (CIS); and
- Meter Data Management System (MDMS).

Replacement of these two systems is necessary to support smart metering, self-service options, and pricing programs. Current customer offerings are restricted due to the limitations of our current systems (e.g., net metering). To offer certain additional programs, PGE must either invest in the development of our current systems (with additional programming costs) or manually process customer enrollment, participation, billing, and payment. Additional functionality provided by new modern systems will furnish PGE opportunities to improve the way we engage and serve our customers. In our last two general rate cases (UE 262, PGE Exhibit 900, Section III; and UE 283, PGE Exhibit 1000, Section IV), we discussed CET in detail.

Q. How were the CET-related O&M costs treated in the two previous general rate cases?

A. In UE 262, the parties agreed that PGE would treat the $8.0 million in 2014 CET O&M costs as a regulatory asset and amortize the amount over the five-year development life of the project (i.e., 2014-2018). In UE 283, PGE applied the same methodology, where CET O&M costs were again treated as a regulatory asset to be amortized over the four-year remaining development life of the project (i.e., 2015-2018).

Q. Does PGE propose to apply the same deferral methodology to 2016 CET O&M costs?

A. Yes. We propose that the $4.7 million of 2016 CET O&M costs be deferred and amortized over the three-year remaining development life of the project (i.e., 2016-2018). The result of these mechanisms is that for 2014, 2015, and 2016, CET O&M costs will net to the three vintages of amortization as reflected in Table 2, below, and listed in Table 1, above.

Table 2
CET Deferral Amortization ($000)

CET Vintage	2014	2015	2016	2017	2018	Total CET Expense for Vintage Year*
2014	$1,600	$1,600	$1,600	$1,600	$1,600	$8,000
2015		$1,333	$1,333	$1,333	$1,333	$5,332
2016			$1,558	$1,558	$1,558	$4,675
Totals	**$1,600**	**$2,933**	**$4,491**	**$4,491**	**$4,491**	**$18,007**

* May not sum due to rounding

Q. What CET activities were implemented in 2014?

A. In 2014, CET activities fell primarily into two categories: 1) prepare for, select, and design the new customer systems; and 2) operational efficiency and effectiveness initiatives.

1. Prepare for, select, and design new customer systems:
    - Developed high-level system requirements for the future CIS and MDMS.
    - Implemented a data quality tool to assure integrity of customer data for completeness, accuracy, and consistency in preparation to move customer data to the new systems.
    - Launched a governance process that ensures consistency and accuracy of customer data is retained as new systems are implemented.
    - Simplified the current rate code complexity and reporting to facilitate seamless transitions to the new CIS.

- Selected hardware and software packages that best meet PGE's customer, business and regulatory requirements.[7]

2. Operational efficiency and effectiveness initiatives:
   - Advanced the current workforce planning and scheduling capabilities, which optimizes the allocation of employees to identified workloads.[8]
   - Finalized performance metrics for implementing a tool to consistently measure and manage individual and team performance.[8]
   - Created a business model for organizational alignment within Customer Service Operations to support employee adoption of new processes and systems, which will improve the likelihood of realizing benefits.
   - Launched a campaign to increase customer enrollment in paperless billing.
   - Completed work on the IVR system, enhancing reporting features.
   - Completed a three-year roadmap to improve our analyses on customers' evolving needs and preferences for products and services.

Q. What CET program activities are planned for 2015?

A. As discussed in UE 283, CET activities for 2015 fall primarily into two categories: 1) design and implementation of new systems; and 2) continued work on operational efficiency and effectiveness initiatives.

1. Design and implementation of new systems:

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[7] Contract execution is expected in early 2015.

[8] These new business processes and tools are forecasted to be fully operational in 2015.

- Begin the implementation process for the new CIS and MDMS. 2015 activities will focus on designing business processes plus the operation and interaction of new technologies within different parts of the Customer Service organization.
- Define the technical architecture of the various systems that will interface with the new CIS and MDMS.
- Begin build-out of the new customer systems. In addition to CIS and MDMS, PGE will implement a knowledge management system to better manage the detailed work instructions for Customer Service operation functions. It will have user-friendly features such as "search," "help," and "frequently asked questions." This tool supports employees, helping them to better serve our customers.

2. Continued Operational efficiency and effectiveness initiatives:
   - PGE will complete activities that optimize the allocation of workload to employees across Customer Service departments, and help manage individual and team performance.[9]
   - Launch a 2015 campaign to increase paperless bill enrollments with the goal of moving from 15% enrollment to 40% enrollment by 2018, resulting in a cost savings of approximately $1.4 million per year when fully implemented.

Q. Please describe 2016 CET activities.

A. CET activities for 2016 again fall primarily into two categories: 1) finalize system build-out and testing for system replacement; and 2) employee preparedness for the adoption of new processes and systems.

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[9] These new business processes and tools will become fully operational in 2015.

1. <u>Finalize system build-out and testing for system replacement:</u>
    - Focus on system replacement and associated activities to ensure that data and process integrity remain intact through rigorous system build out and testing.
    - Test the new systems by completing "dry-runs" or practice "go-lives" to test system stability and performance.
    - Design and test the PGE bill within the new CIS.
2. <u>Employee preparedness for the adoption of new processes and systems</u>:
    - Align the organization to support employee adoption of new processes and systems by supporting training activities, providing opportunities for employees to practice using the new system, and supporting leadership as they guide the workforce through changes that include process and procedures.

Q. Does the 2016 forecast include any savings associated with the implementation of various CET initiatives?

A. Yes. Expected 2015 to 2016 savings attributable to CET initiatives will result in:

- A $450,000 reduction in labor costs within the Contact Center and back office; or 9.7 FTEs. This reduction allows total Customer Service FTEs to remain relatively flat with a net increase of only 0.2% annually.
- A $391,000 reduction in non-labor costs due to reduced paper and postage through increased adoption of paperless billing.

Q. Please describe what, if any, changes were made to the CET timeline and roadmap since PGE's last general rate case.

A. We have made minor adjustments to the CET roadmap as provided in PGE Exhibit 901, with minimal impact on costs. The CET roadmap establishes the sequence of the various initiatives from 2012 through 2018 and factors the interdependencies of initiatives to maximize operational efficiencies and effectiveness.

IV. Fee-Free Bank Card

Q. Please describe how your FFBC program aligns with PGE's overall payment strategy.

A. PGE's payment strategy is to offer customers the payment options they expect while managing the costs of those options. Customers have consistently asked for FFBC payment for a number of years based on their experience with other service providers, including other utilities. Due to FFBC's higher cost when compared to payment options such as electronic checks, our communication and promotional activity will primarily focus on encouraging customers to pay their bill with the least-cost payment methods.

Q. Please describe PGE's residential FFBC program.

A. The target date for the FFBC program's implementation was revised to November 1, 2014 as stipulated in Docket No. UE 283 and approved by Commission Order No. 14-422 (see Appendix A, page 4). PGE and its third-party vendor worked to accelerate the program's development to deliver program functionality ahead of the November 1 target. As a result, PGE implemented its FFBC program on September 30, allowing residential customers to pay their electric bill with a bank card, either a credit or debit card, without fees when using the IVR phone system, a mobile platform, or online at our website (PortlandGeneral.com).

Q. Since implementation of the residential FFBC program on September 30, 2014, what is the current trend of customers using the program and the associated costs?

A. Through December 31, 2014, PGE received 96,042 bank card payments via its IVR and web payment channels or 4.6% of all residential payments. Prior to the implementation of the FFBC program, when customers were charged a fee for a bank card payment, card use averaged approximately 3.0% of all payment transactions. PGE's costs associated with these FFBC payments were approximately $151,000. In accordance with the UE 283 stipulation, PGE will submit a report to the Commission by March 1, 2015, to provide an update on customers using the program through December 31, 2014.

Q. What are PGE's projections for FFBC program costs and estimated adoption rates in 2015?

A. The FFBC program in 2015 consists of: 1) residential customers only; and 2) a target adoption rate of 11.1% by December 2015. Based on these criteria and in accordance with the UE 283 stipulation, PGE is budgeting approximately $1.1 million for credit and debit card payments in 2015.

Q. What is the basis of the 2015 adoption rate and associated costs?

A. These amounts are consistent with the Public Utility Commission of Oregon Staff's (Staff) linear adoption forecast as developed in the UE 283 proceeding, which calls for an 11.1% adoption rate by December 2015.

Q. What has PGE forecasted for the program in the 2016 test year?

A. For 2016, PGE forecasts a total of $2.3 million for the FFBC program, which represents an additional $1.2 million over the 2015 budget. Of this increase, $0.2 million is based on expanding the program to small non-residential customers and $1.0 million is related to an increase in the residential adoption rate to 17.0% by December 2016.

Q. What specifically does the expansion to small non-residential customers entail?

A. The FFBC program will expand to include non-residential customers on PGE Schedules 32 and 47, which represent PGE's small commercial customers that typically use bank cards for payment of business expenses. Using the linear adoption model described above, PGE anticipates a 10% adoption rate for small non-residential customers by December 2016.

Q. Why is the program expansion being limited to only small non-residential customers?

A. Restricting participation serves to keep program associated fees, costs, and risks lower.

Q. Please describe your adoption methodology for the 2016 FFBC program.

A. Adoption rate calculations and eligible rate schedules are illustrated in PGE Exhibit 902. As noted above, the adoption rate methodology parallels the linear model for 2015, but begins with zero adoption for small non-residential customers in 2016.

Q. How does the FFBC program benefit PGE customers?

A. For customers who participate, bank cards are easy and convenient and provide an additional tool to manage cash flow. Bank card payments also provide a convenient way to consolidate payments with other bills. Over time, further analysis may bear evidence of reduced payment arrears or write-offs because financially-challenged customers may use bank cards to extend payment until they have sufficient funds to pay. If this proves to be the case, all customers will benefit from lower write-off costs in the future.

Q. What are the characteristics of residential customers who use the FFBC program?

A. PGE Exhibit 903 provides data collected on residential customer use of the program since its inception on September 30, 2014. We reviewed the profiles of residential customers who used bank cards in the first three months of fee-free availability. Early results show that the residential customers paying with bank cards are more likely than the general residential customer base to:

- Rent (rather than own) an electrically-heated home or apartment;
- Have poor credit and have received multiple overdue bill notices in the past year;

- Have lower income (i.e., lower than average income of $40,000[10]) and education (i.e., minimal or no college[11]); and
- Have opened their account within the last two years.

These are very early results from the program and the characteristics of customers using it may change over time.

[10] Lower income as defined by Axciom, PGE's third party vendor.
[11] Lower education as defined by Axciom, PGE's third party vendor.

V. Conclusion

Q. You stated that PGE's goal for Customer Service is to deliver value to its customers by providing excellent service at a reasonable price. Are the activities planned within your Customer Service organization necessary to achieve this goal?

A. Yes. The initiatives 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 delivering the products and services that provide benefits and convenience to customers as well as enhance and simplify the customer experience.

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 Portland General Electric Company 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 one 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 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 the Company. 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-six 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?

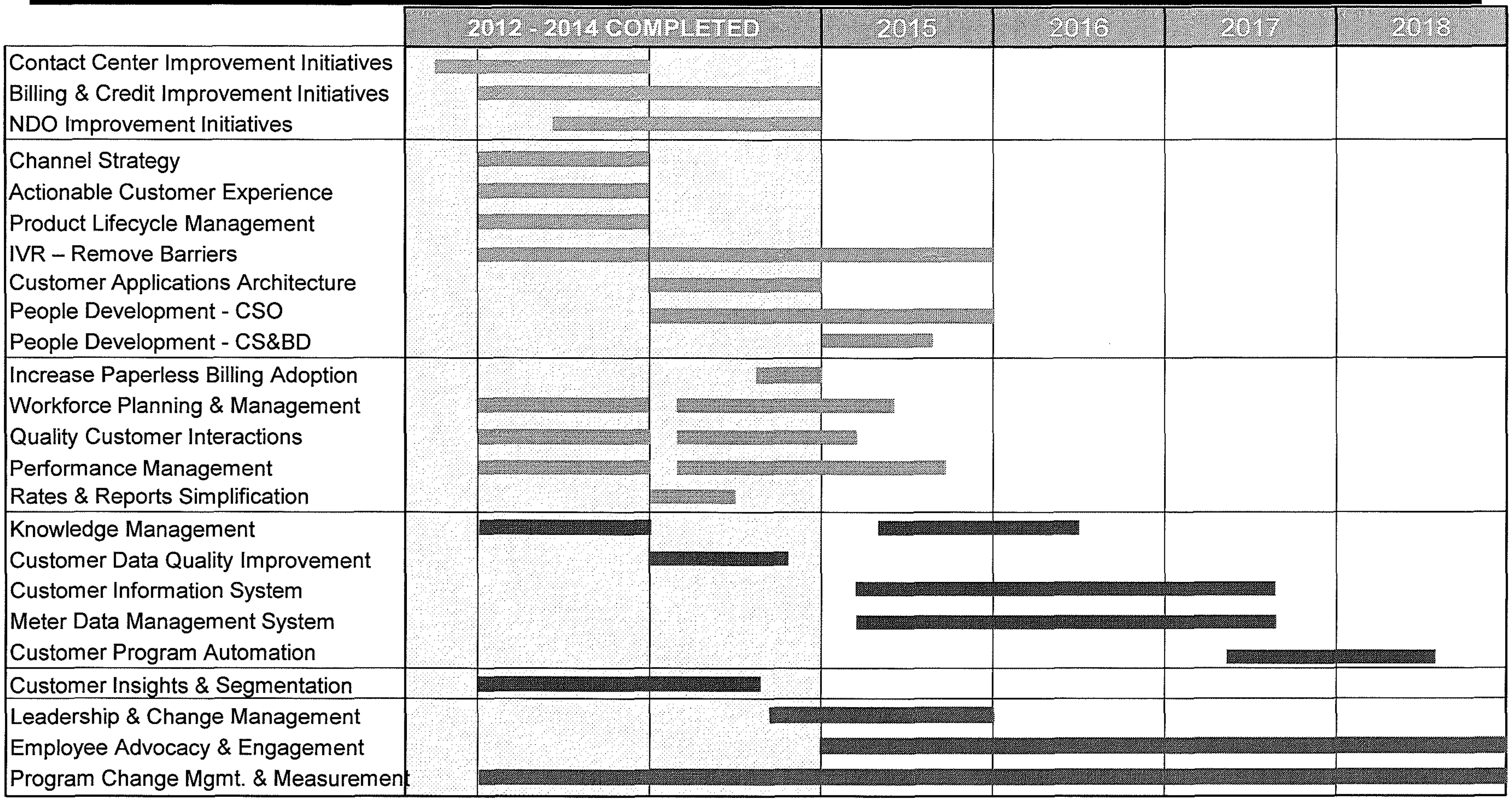
A. Yes.

List of Exhibits

PGE Exhibit	**Description**
901	CET Roadmap
902C	FFBC Adoption
903	FFBC Customer Profile

Customer Engagement Transformation

Roadmap January 2015



CATEGORIES: Improvement Initiatives; Strategy & Governance; Operational Efficiencies; Analytics & Reporting; Systems; Change Management

*Roadmap as of Jan. 2015. This Roadmap is a living document and subject to change.

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

Customer Engagement Transformation

Category Descriptions

Improvement Initiatives: Implement numerous process improvements to increase overall effectiveness and efficiency in the operational areas of Contact Center, Billing, Credit, and Network Data Operations.

Strategy & Governance Initiatives: Provides the long-term strategy for gaining better insight into customer behaviors - such as channel preference (web, phone, community office, etc.) – to deliver products and services faster and more cost effectively. Also develops the high-level system requirements and selects the software packages that best meet PGE's customer and regulatory requirements.

Operational Efficiencies: Enhance current workforce planning and scheduling tool to optimize the allocation of employees to workloads across Customer Service, increasing employee productivity and enabling cost efficiency. Finally, PGE will design and implement a tool for managing individual and team performance metrics.

System Replacements: Preparation for system replacements by completing technical activities such as reviewing customer data for accuracy and consistency; involves the purchase of a data quality tool. This effort includes implementation of: a new Customer Information System (CIS) and Meter Data Management System (MDMS); a new Knowledge Management System that supports employees with convenient features such as “search”, “help”, and “frequently asked questions”; and a Customer Program Automation system that will utilize improved customer data through automation to deliver accurate measurement of program adoption and effective, efficient product management.

Analytics & Reporting: Update and enhance customer data in order to drive a more tailored, targeted marketing of products and services to customers.

Change Management: Provides overarching programmatic support to improve the rate of employee adoption and proficiency in using new processes and systems in order to realize benefits earlier and reduce project risk.

Exhibit 902C

Confidential

Significant Attributes of Fee-Free Bank Card Users

Profile is for data of FFBC users as of November 30, 2014

Attribute	Profile %[1]	Reference %[2]	Attribute	Profile % - Reference %	Index[3]
Renter	72%	44%	Renter	27%	162
Education (Acxiom[4]): High School-VoTech	61%	50%	Education (Acxiom): High School-VoTech	12%	124
15-Day Notice(s) Past 12 Mo. (CIS)[5]	51%	25%	15-Day Notice(s) Past 12 Mo. (CIS)	26%	203
PGE Segment (Acxiom): Continually Connected[6]	49%	14%	PGE Segment (Acxiom): Continually Connected	34%	335
Account Years: Under two years	46%	27%	Account Years: Under two years	20%	173
PGE Credit: Not Excellent (CIS)	41%	16%	PGE Credit: Not Excellent (CIS)	24%	252
5-Day Notice(s) Past 12 Mo. (CIS)	38%	15%	5-Day Notice(s) Past 12 Mo. (CIS)	23%	255
Low-Income (Acxiom): Under $40,000	37%	26%	Low-Income (Acxiom): Under $40,000	12%	145
Occupation (Acxiom): Blue Collar	22%	15%	Occupation (Acxiom): Blue Collar	7%	148
Time-Payment Agreement (TPA)	11%	3%	Time-Payment Agreement (TPA)	8%	364
Agency Assistance Past 12 Mo. (CIS)	6%	3%	Agency Assistance Past 12 Mo. (CIS)	2%	168

Uncommon Attributes of Fee-Free Bank Card Users

Attribute	Profile %	Reference %	Attribute	Profile % - Reference %	Index[3]
Affordability Level (Acxiom): High	30%	54%	Affordability Level (Acxiom): High	-23%	57
Education (Acxiom): College	30%	35%	Education (Acxiom): College	-5%	86
High-Income (Acxiom): $75,000 plus	29%	42%	High-Income (Acxiom): $75,000 plus	-13%	69
Homeowner	28%	56%	Homeowner	-27%	51
Account Years (CIS): 6+ years	27%	51%	Account Years (CIS): 6+ years	-24%	53
Education (Acxiom): Graduate School	9%	16%	Education (Acxiom): Graduate School	-7%	57

[1]Percentage of profile segment (in this case, customers that use Fee-Free Bank Card) that exhibit an attribute

[2]Percentage of all PGE Residential customers that exhibit an attribute

[3]Index score of 100 would represent an attribute in which the Profile percentage and Reference percentage are the same

[4]Acxiom is an enterprise data, analytics and software as a service company with 7,000+ global clients that PGE purchases consumer data from

[5]PGE's Customer Information System

[6]PGE's Continually Connected customer segment show many of the following characteristics: younger,challenges, high eligibility for energy assistance, highest web one-time payment. Customers in this segment have high contact rates with PGE, and the highest propensity to communicate via CSR and Community Office

FFBC Bill Matrix Transactions Processed				
Month Year	Total Residential Transactions	Credit Card Transactions	Debit Card Transactions	Percentage of Bank Card Payments
9/30/2014 Launch	29803	614	114	
Oct-14	733,110	27,068	5,640	
Nov-14	590,035	22,240	4,758	
Dec-14	734,621	29,753	5,855	
Total	**2,087,569**	**79,675**	**16,367**	**4.6%**

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Patrick G. Hager
Brett Greene

February 12, 2015

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric ("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 qualifications are included at the end of PGE Exhibit 400.

My name is Brett Greene. I am the Assistant Treasurer and Director of Treasury & Tax for PGE. I am responsible for managing the company's treasury function including financing as well as the tax department. My qualifications are also 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 2016 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 2016, 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 7.667% cost of capital for the 2016 test year. This cost of capital includes a 9.9% authorized Return on Equity (ROE) based on the recommended range

[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)

provided by of Dr. Villadsen in PGE Exhibit 1100. This point estimate is for revenue requirement purposes. Table 1 below shows the recommended cost of the two components of PGE's capital, common equity and long-term debt. Table 1 also shows PGE's forecasted 2016 capital structure.

Table 1
PGE's Weighted Cost of Capital
Test Year 2016

Component	Average Outstanding ($000) [1]	Percent of Capital [2]	Component Cost	Weighted Cost
Long-term Debt	$2,441,400	50.00%	5.433%	2.717%
Common Equity	$2,443,817	50.00%	9.90%	4.950%
Total	**$4,885,217**	**100.00%**		**7.667%**

[1] "Average Outstanding" reflects PGE's projected average values of long-term debt and common equity for 2016.

[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 Mr. Greene's 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 and counterparty credit risk:

- 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 return on equity that is commensurate with the return on equity 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 facing our customers; and
- Manage counterparty credit risks, wholesale and retail.

A. Solid Financial Performance

Q. Why is it important for PGE to maintain an investment grade rating?

A. It is essential for PGE to keep an investment grade rating in order to secure financing, both debt and equity, at reasonable rates and to maintain access to wholesale energy markets, especially in today's volatile financial environment. 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 in the wholesale power market.

Q. What does PGE do to maintain its investment grade credit rating?

A. Fundamentally, PGE's credit rating is a function of its financial performance, which is driven by PGE's retail prices and its ability to manage costs. The rating agencies, as well as equity investors, expect companies to 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 which 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 any appropriate mitigation measures. Using all of these measures helps us maintain our financial performance levels that are necessary to maintain our 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 the rating agencies are 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. Yes. PGE received two upgrades on its long-term debt from Moody's in the past two years. PGE's long-term debt ratings from Moody's are two notches higher than Standard & Poor (S&P). PGE will continue to pursue an upgrade from S&P, 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 maturity schedules closely match investment lives of our capital projects. We try to use First Mortgage Bonds (FMBs) as the primary debt because it has lower cost than unsecured alternatives. PGE evaluates private placement market rates, bank term loans and delayed draw/forward structure 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 its long-term financing proceeds to meet those requirements. PGE has recently 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. Our desired long-term capital structure is 50 percent equity and 50 percent long-term debt, although it may fluctuate from year to year. We believe that the 50 percent equity in our capital structure helps us to better weather difficult financial situations, such as issuing long-term debt to finance our major construction programs. 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, as we look towards a possible new construction cycle, we are likely to continue to use additional equity, stock repurchases, capital expenditure programs, 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 2013, industrial energy deliveries were affected by the partial or full closure of paper manufacturers and a decline in deliveries to our solar manufacturing customers. 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 paper being the most relevant example. Our load forecasters work closely with PGE's Key Customer Managers to gain 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 by 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 as well as a minimum credit rating.

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 picture).

- 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 continually 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 operating our electric utility business.

Q. What were the results of your analysis?

A. Based on our analysis, we determined that PGE can safely reduce the total size of the credit facilities from $700 million to $500 million due to forecasted lower liquidity needs in support of power supply and general operations. This reduction in revolving credit capacity is aligned better with PGE's current risk profile and the substantial completion of generation projects on-line in 2014, 2015 and early 2016. In addition, this reduction is a result of a reduction in PGE's short generation position and low natural gas prices.

Table 2
Power Supply Liquidity Analysis
($ millions)

	Collateral Range	Revolver Need
20% Price Change	$70-$90	$80
50% Price Change	$200-$220	$210

In determining the appropriate size of credit facilities to support general operations, we consider such factors as an interruption in operational cash flow, lower earnings, temporary lack of access to capital markets, poor hydro and wind conditions, and forced plant outages. We developed several scenarios to "stress" the liquidity requirements of general operations. Under these scenarios, PGE would require approximately $373-$563 million of liquidity.

Q. Did you consider any other factors?

A. Yes. In our analysis, we also considered one and two 'notch' downgrades by S&P and Moody's. Such downgrades would significantly inhibit PGE's ability to access the capital markets to support our power operation needs as well as our general operations and capital investment plans and would require PGE to post additional collateral with our wholesale power counterparties.

Q. Can you briefly summarize Moody's and S&P's liquidity methodologies?

A. Yes. Moody's has three ratings for a company's liquidity: good, adequate, or inadequate. If a company's sources of liquidity to its uses of liquidity is 200% or above, then Moody's would classify its liquidity as "good." If this ratio is 100%, then Moody's would consider the company's liquidity as "adequate." Finally, if the ratio is less than 100%, then Moody's would consider the liquidity "inadequate."

S&P has five ratings: exceptional, strong, adequate, less than adequate, and weak. S&P calculates the sources and uses of liquidity under normal business conditions, then "stresses" the liquidity by reducing the sources of liquidity in a specific manner through Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA). Since the focus is on the first three ratings, we describe only those three.

In the unstressed scenario, if the company has a minimum ratio of 2x (sources of funds to uses of funds) and its sources of funds is still positive after a 50% decline in EBITDA, then S&P rates the company "exceptional." In the unstressed scenario, if the company has a minimum ratio of 1.5x and its sources of funds are still positive after a 30% decline in EBITDA, then S&P rates the company "strong." Finally, to be "adequate," in the unstressed scenario, the company must have a minimum ratio of 1.2x and its sources of funds must be positive after a 15% decline in EBITDA.

Q. What were the results of your analyses?

A. For Moody's criteria, our analysis found that our liquidity profile would be rated "adequate" in 2015 and "good" in 2016. For S&P, we would be rated "adequate" with minimal upside potential based on their rating criteria. Based on this set of analyses, we determined that our current revolver capacity of $700 million could be reduced to $500 million for the test year. We filed an application in January 2015 seeking to reduce our revolver capacity and expect it to be approved.

III. Uncertainty in Regulation, Accounting, and Financial Markets

A. Regulation and Financial Markets

Q. What are PGE's current bond ratings?

A. PGE's current bond ratings for secured (first mortgage) long-term debt are A1 from Moody's and A- from S&P. Ratings for unsecured debts are A3 and BBB respectively. PGE's credit ratings 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. 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.[5] Moody's has also become more positive regarding regulation overall, increasing most electric utility bond ratings in 2014. However, as we noted above, the ratings agencies remain concerned regarding the asymmetric nature and size of the deadbands in the PCAM. For example, S&P states "POR has historically traded at a discount to its peers primarily due to perceived asymmetric risk around fuel and power supply cost variability."[6]

Q. Have other financial analysts expressed concerns regarding the PCAM?

A. Yes. 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. Deutsche Bank mentions the following risks for PGE: risks of capex disallowances and inability to earn close to the authorized return, the possibility of underrecovery of fuel and purchased power expenses, the company's small size could limit its access to financing in the event of a severe credit tightening in the economy, and exposure to a single regulatory jurisdiction.[7] J.P. Morgan lists PGE fuel and purchased power recovery mechanism as a source of risk: "any combination of a reduction in hydro

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[5] "POR Strong Results; '14-'16 Estimates Raised- Hold." Gabelli & Company- October 29, 2014.
[6] "POR: Raising EPS and PT on Load Growth and Large Rate Base Opportunity Ahead"-KeyBank, October 28, 2014.
[7] "Planning for next round of growth." Deutsche Bank Market Research- 30 October 2014

conditions or an increase in the price of coal or natural gas could adversely impact POR's near-term earnings."[8]

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. As we discussed above, 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 the 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 requirements and increasing supervision for the largest (Systemically Important Banks); and adopting national initiatives (Dodd-Frank and Volker rule).

[8] "In-line Quarter; Next Rate Filing to Come Early Next Year."-J.P.Morgan-29 October 2014

Q. How will 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 access. Second, banks were forced to participate in the liquidity scenarios outlined by central banks around the world, encouraging many to keep 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)[9], leaving less available for lending.

Q. Will these new requirements affect PGE's ability to access funds?

A. Yes. Dodd-Frank is forcing banks and marketers to decide if the added cost of compliance and reporting is worth the margins of remaining a liquidity provider. In 2015, we could see some financial stress passed through to PGE and other utilities as banks comply with the Basel III regulation (full compliance is required by 2019). The impact of this could be an increase in the costs of carrying credit facilities, as well as a reduction in tenor, and an upward pressure on the ability to execute FMB issuances at the prices (spreads) that we have seen during the last couple years. In short, these new requirements have tightened the availability of funds, which would drive borrowing costs higher.

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 quasi fixed payments from long-term power purchase agreements (PPAs). S&P believes that because of these quasi-debt instruments an adjustment must be made to the capital structure to reflect the additional leverage of PPA contracts. Significant increases in the

[9] http://research.stlouisfed.org/fred2/series/EXCSRESNS.

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 to 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 Securities and Exchange Commission (SEC). ASC 810 requires consolidated financial statements to reflect total assets under control and total liabilities for which an entity is responsible.

Under ASC 810, 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, PGE may be required to consolidate their financial results with that of PGE. 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 to 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.

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 market conditions during 2013 – 2014 and going forward?

A. Yes. First, we should note that 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 continued to grapple with the challenge of taking appropriate fiscal and monetary policy actions in the aftermath of the financial crisis. Of significant concern is the euro area. The euro area grew slightly in early 2014, but the growth slowed in the second half of the year and there is concern that the area may be entering a deflation state. 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 area as well as the strengthening dollar. Of particular concern in the euro zone is the recent political development in Greece, which elected a government that pledged to cancel the austerity program imposed by outside financial entities in exchange for the additional lending to Greece. The current government has stated that it will impose no additional austerity measures, which would result in Greece not meeting the targets set by the financial lenders. This situation will likely continue into 2015 and possibly 2016 and could likely have an impact on the financial markets.

Another macroeconomic factor that needs to be considered is the future rise of interest rates. The Fed ended its quantitative easing in 2014 and most economists expect long-term interest rates to rise. The question is when will interest rates begin to rise and to what level? This is a very difficult question to answer but we concur with Dr. Villadsen's discussion, when she says that consensus forecasts are substantially higher than the recent 2.1-2.4% yield on 10-year U.S. government bonds (PGE Exhibit 1100, Section III). We also note that an additional driver of increased interest rates is the strengthening U.S. economy with growth close to or exceeding 4.0% during the second and third quarters of 2014.

Q. Do potential risks remain in the U.S. or global economies?

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 values adjustment risk, usually by purchasing default protection on the sovereign or shorting government bonds. This will exacerbate losses as the sovereign bonds' value falls further.

Market constraints may necessitate use of proxies for the sovereign, 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 2016?

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, 2015, as well as bond issuances and retirements expected in 2015. 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 3 below summarizes PGE's cost of long-term debt for test year 2016.

Table 3
PGE's Cost of Long-Term Debt ($000)

	2016 Forecast	UE 283 Order No. 14-422	Difference
Principal Amount	$ 2,441,400	$ 2,321,400	$ 120,000
Annual Interest Cost	$ 132,641	$ 126,354	$ -6,287
Effective Interest Rate	**5.433%**	**5.443%**	**-0.010%**

Q. What future debt issuances did you include in your analysis?

A. We expect to issue $255 million in long-term fixed rate debt during 2015 (we already issued $75 million in January 2015), and have included the full amount in our calculation as our current best estimate. At this time, we expect to issue $60 million of long-term debt in 2016. We will provide an update to our cost of long-term debt in our rebuttal testimony, which will include any changes in long-term debt for 2016.

Q. What is the expected term, coupon rate, and issuance cost for the bonds to be issued in 2015?

A. PGE currently expects to issue three tranches of FMBs in 2015: (1) a 15-year tranche that already has been issued with a locked-in coupon rate of 3.55%; and (2) two 30-year tranches that will carry an estimated coupon rate of approximately 5%, which we expect to issue in late 2015. 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 the PGE's investment banks and a forecast of treasury rates from Global Insight.

Q. Is any long-term PGE debt maturing in 2015 and/or 2016?

A. Yes. $70 million of 3.46% 5-year FMBs are maturing on January 15, 2015; and $67 million of 6.80% 7-year FMBs are maturing on January 15, 2016. The last debt issuance and redemption is detailed in PGE Exhibit 1001.

V. Capital Structure

Q. How did you determine the appropriate capital structure for 2016?

A. We evaluated PGE's capital structure using the forecasted income statement and balance sheet for 2016. 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 283 (Order No. 14-422). 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 2016?

A. No. At this time PGE does not anticipate additional equity issuances but we will provide an update if our financing plans change.

Q. PGE issued 2.4 million shares of common equity in 2013. How did PGE raise this equity?

A. PGE used a forward structure that is commonly used by companies that allows us to lock in a common share issuance price but actually issue the shares and receive cash when PGE requires the cash and to maintain a balanced capital structure. This forward structure allowed PGE to lock in equity pricing at a favorable at that time level of $29.50 per share. PGE has drawn a portion of the cash and issued 1,665,000 of the shares at closing and an additional 700,000 shares in August of 2013. We expect to exercise the forward contract and issue the remaining 10.4 million shares in 2015, representing approximately $270 million in proceeds, as our capital expenditures progress for our new Carty generating plant. This method of equity issuance also allows PGE to better manage our desired long-term 50/50 capital structure.

Q. How did customers benefit from the forward structure?

A. Because PGE can draw on the forward structure as it needs cash, we minimize the amount of 'idle' cash and better balance our capital structure over time. Thus, PGE's financing costs should be lower, all else equal, because our capital structure will be less volatile.

Q. Are you seeking a different capital structure than that in UE 283?

A. Not at this time. In UE 283, Order No. 14-422 adopted a settlement among 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. PGE expects the level of equity to exceed 50% by the end of the test year to accommodate the continued Carty construction progress.

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 minimizes 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 finishes 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, as we discuss below, 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 the timing of it; and volatility in electricity usage because of sudden, unexpected weather changes and severe storms. This weather risk is not mitigated by our decoupling mechanism. These risks can potentially force PGE to purchase more spot energy, when the markets may be tight. The costs resulting from these purchases could be greater than what is included in customer prices.
- Regional economic weakness: Regional economic weakness can adversely affect PGE's revenues. Weakness in the state of Oregon, can lead to a decline in electricity usage as customers become more conservative. This can negatively impact PGE's revenues, thereby reducing PGE's profits, which negatively affect PGE's retained earnings and returns to investors. Lower retained earnings affect our ability to reinvest in the business. Oregon's economy was especially hard-hit during the recession and financial crisis of 2008 and has not completely recovered since then. The preliminary estimate for the state of Oregon unemployment rate in October 2014 was 7.0%, only 8 other U.S. states had worse unemployment rate than Oregon, and U.S. average rate was 5.8%.

- Uncertainty regarding financial and business operations contingencies: as noted in our SEC annual 10-K and quarterly 10-Q filings[10]. PGE could be vulnerable to cyber security and physical assets attacks. Electric industry is going through accelerated technological changes which can make a basic premise of 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 J.P. Morgan in our work papers.

Q. Can PGE mitigate these risks?

A. PGE can manage some of these risks, but not others. For risks that PGE can manage, PGE develops management capabilities and core competencies, as well as establishes strong processes and procedures to mitigate some of the risk. PGE is proactively implementing programs that will better prepare us for the operational impacts of adverse events. For

[10] http://investors.portlandgeneral.com/sec.cfm
Starting with page 117,Note 18- 2013 SEC Form 10-K
http://files.shareholder.com/downloads/POR/3830456804x0xS784977-14-59/784977/filing.pdf
Starting with page 25 Note 7- the most recent 10/28/14 SEC Form 10-Q

example, recovery from catastrophic events remain a key strategic focus of PGE. The office of Business Continuity and Emergency Management has developed formal recovery plans to address disasters and implement emergency management procedures. 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 storage solutions and performing cost-benefit analysis of re-establishing ability of gas plants to run on oil if pipeline interruptions occur.

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 and aware and capable of responding to them to the best of our ability.

Q. Could the risks addressed above alter the cost of capital you request?

A. Yes. If these risks result in financial distress to PGE and/or its peers, the cost of long-term debt and the cost of equity will increase, with a resulting long-term cost impact on customers through increased borrowing costs and possibly a ratings downgrade.

VI. Qualifications

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

A. I received a Bachelor of Science degree in Business Administration from the University of Portland in 2000. I received a Master of Science in Taxation from Golden Gate University in 2009. I joined PGE in 2010 as Tax Manager and was Manager of Corporate Finance and Assistant Treasurer from August 2012 to December 2012. Since January 2013, I have held the title of Assistant Treasurer and Director of Treasury & Tax.

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, 2016 - 2016 Test Year

Updated 01.12.2015

(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 f Refunded Issu (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	0.842%	0.079%
2	7000000022	Series VI M	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	2.106%	0.147%
3	7000000023	Series VI M	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	2.106%	0.148%
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	7.370%	0.489%
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	4.212%	0.281%
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	7.160%	0.420%
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	5.475%	0.323%
8	7000000266	FMB	5.800% Series	12-Dec-07	1-Mar-18	10	5.800%	$75,000,000	$637,500	$0		$74,362,500	5.912%	99.150%	$75,000,000	$74,362,500	3.159%	0.187%
9	7000000693	FMB	6.800% Series	15-Jan-09	15-Jan-16	7	6.800%	$67,000,000	$0	$0		$67,000,000	6.919%	0.000%	$0	$0	0.000%	0.000%
10	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	12.635%	0.786%
11	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	6.317%	0.346%
12	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	4.119%	0.213%
13	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	0.994%	0.053%
14	7000001028	FMB	3.810% Series	15-Jun-10	15-Jun-17	7	3.810%	$58,000,000	$351,307	$0		$57,648,693	3.910%	99.394%	$58,000,000	$57,648,693	2.443%	0.096%
15	2013-1	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	6.317%	0.285%
16	2013-2	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	3.159%	0.143%
17	2013-3	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	4.422%	0.211%
18	2013-4	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	2.106%	0.103%
19	2014-1	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	4.212%	0.186%
20	2014-2	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	4.212%	0.189%
21	2014-3	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	3.369%	0.121%
22	2015-1	FMB	2015 Forecast	15-Jan-15	15-Jan-25	15	3.550%	$75,000,000	$375,000	$0	7	$74,625,000	3.593%	99.500%	$75,000,000	$74,625,000	3.159%	0.114%
23	2015-10	FMB	2015 Forecast	15-Oct-15	15-Oct-45	30	5.000%	$90,000,000	$450,000	$0	7	$89,550,000	5.032%	99.500%	$90,000,000	$89,550,000	3.790%	0.191%
24	2015-11	FMB	2015 Forecast	15-Nov-15	15-Nov-45	30	5.000%	$90,000,000	$450,000	$0	7	$89,550,000	5.032%	99.500%	$90,000,000	$89,550,000	3.790%	0.191%
25	2016-1	FMB	2016 Forecast	15-Jan-16	15-Jan-46	30	5.190%	$60,000,000	$300,000	$0	8	$59,700,000	5.223%	99.500%	$60,000,000	$59,700,000	2.527%	0.132%
			Annual expense from loss on reacquired debt							$17,139		($17,139)						
			Totals					$2,441,400,000	$17,783,487	$16,728,156		$2,406,888,357			$2,374,400,000	$2,339,905,496	100.00%	5.432%
			Cost of LT Debt (includes annual expense from loss on reacquired debt)															5.433%

Losses on Other Reacquired Debt	Issue Date	Mat. Date	Reacquisition Date	Gross Proceeds	Total Gain/Loss to Amortize	2016 Expense
7000000(5.450% Colstrip 98B Fixed	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 Assume 5% Coupon for 30 year maturity and 0.5% Cost of Issuance
8 Assume 4.19% Global Insight 2016 30 year treasury rate plus a spread of 100

Standard & Poor's and Moody's Investors Service Credit Ratings

	S&P	Rating Date	Moody's	Rating Date
Senior Secured Debt	A-	2/21/2012	A1	1/30/2014
Senior Unsecured	BBB	2/21/2012	A3	1/30/2014
Short-term/ Commercial Paper	A-2	2/21/2012	P-2	7/2/2012

"Credit Opinion: Portland General Electric Company" February 21, 2012. Standard & Poor's
"Credit Opinion: Portland General Electric Company" July 2, 2012. Moody's Investors Service
"Rating Action: Portland General Electric Company" January 30, 2014 Moody's Global Credit Research

UE 294 / PGE / 1100
Villadsen

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Return on Equity

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bente Villadsen

February 12, 2015

Table of Contents

I. Introduction and Summary

Q. Please state your name, occupation and relationship with Portland General Electric ("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 (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, 2016.

My qualifications are included at the end of my testimony in Section VII.

Q. Please summarize your results.

A. The estimates I rely on are detailed in Table 1 below.[1]

Table 1: Summary of ROE Estimates for PGE

	Range of Estimates
DCF models	9.8% - 11.2%
Risk Premium models	10.0% - 10.7%
Other Tests[2]	9.8% - 10.2%
Overall Range	9.8% - 11.2%
Point Estimate	10.25%

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 10.0%

[1] The Oregon Public Utilities 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] I use the CAPM as a check, which results in an ROE of 9.8% to 10.2%. The average allowed ROE for integrated electric utilities in 2014 was 9.96%. See PGE Exhibits 1103 and 1105 for details.

using a combination of the Blue Chip and the Office of Management and Budget (OMB) long-term growth rate (and at 9.8% using Blue Chip alone). Thus, I find a range of 9.8% to 11.2% using the DCF and Risk premium models. This range includes PGE's requested ROE of 9.9%, while the Commission's preferred methods result in a higher ROE. My best point estimate is about 10.25%. I therefore find that PGE's request for 9.9% ROE on a capital structure with 50% equity is reasonable and consistent with my analysis, albeit 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 estimate the cost of equity using standard methods including two versions of the DCF model, three versions of the risk premium model, and as a test, two versions of the Capital Asset Pricing Model (CAPM). My results are checked against the recently allowed return on equity of other integrated electric utilities. 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, currently has a larger amount of power purchase agreements although the magnitude will be reduced going forward, and needs to integrate substantial amounts of new generation (natural gas and wind) into its fleet.

I also note that the average credit rating in my sample is close to BBB+ using Standard & Poor's (S&P) ratings, while S&P rates PGE BBB (Moody's rates PGE higher at A3).[3]

[3] Ratings cited in my work papers are S&P ratings as reported by Bloomberg.

II. Cost of Capital Theory

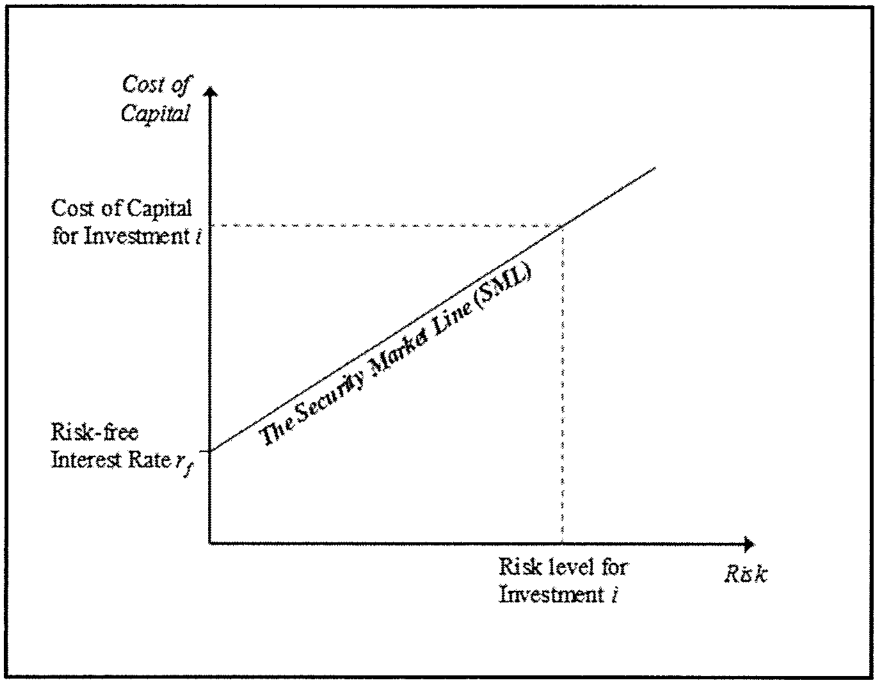
A. Cost of Capital and Risk

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[4] 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 is 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

[4] For the development of a formal link between the cost of capital as defined by financial economics and the expected rate of return for utilities, see Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases," *Bell Journal of Economics & Management Science* 3:58-97 (1972).

(b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.[5]

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 overpay 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

[5] 2013 ORS ¶ 756.040. Available at http://www.oregonlaws.org/ors/756.040.

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 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 allowed 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 Hamada (1979),[6] shareholders in a company with more debt face more equity risk and the return on equity needs to increase. Commission Staff has in past proceedings acknowledged this principle.[7] 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.

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:[8]

$$ATWACC = r_D \times (1 - T_C) \times \%\,D + r_E \times \%\,E \qquad (1)$$

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.[9] 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

[6] Robert S. Hamada, "Portfolio Analysis, Market Equilibrium and Corporate Finance," *The Journal of Finance* 24: 13-31 (March 1969).
[7] See, for example, UE 283 OPUC Staff Exhibit 200, p. 8.
[8] The equation is shown with only debt and common equity. If the capital structure has preferred equity, add the following term ($r_P \times \%\,P$) to the right-hand side of the equation.
[9] 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.[10]

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 both earned and allowed ROE are applied to book value

[10] 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.

capital structures, it is the book value capital structure that is relevant in the risk premium methods.

Q. What is the basis for the development of the method?

A. The weighted-average cost of capital - the same as it is called in textbooks - is the 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. The ATWACC is sometimes mischaracterized in regulatory proceedings and incorrectly criticized, possibly because the critics do not like the method's results, but it is the standard methodology in finance. 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 as is sometimes asserted.

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 more than half of my sample companies is above $5 billion and categorized as large cap companies. In contrast, PGE has a market capitalization of only $2.6 billion and this is at the low end of the mid-cap companies.[11]

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, Morningstar / Ibbotson data indicate that mid-cap companies ($2 - $5 billion in market capitalization) on average have a return on equity that is 1.14% higher than that of large-cap companies.[12] 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 19 companies have a market cap that is more than twice that of PGE.[13] 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 necessarily needs to be somewhere below 1.14% but not zero as the selection of larger companies downward biases the cost of equity estimate.

Q. What other risks create a higher overall risk for PGE?

A. There are several reasons why PGE has a higher level of risk than the comparable companies. It is important to recognize the relative risk of the targeted entity, PGE, versus that of the sample companies used to determine the ROE. Because PGE is substantially

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[11] Value Line Investment Survey, as of 1/7/2015 list Allete, Cleco, IDACORP, and Westar as mid- cap companies, while AEP, DTE, Edison International and PG&E are listed as large cap. Value Line defines mid-cap companies as having a market capitalization between $1 and $5 billion, and large companies as having market values greater than $5 billion.
[12] Morningstar / Ibbotson, *SBBI 2014 Classic Yearbook*, p. 109.
[13] See Table 2 below.

smaller than the average proxy company, continues to integrate a large amount of new generation in its generation mix, and is viewed by Value Line as having a slightly higher relative risk (beta) than the sample, the company faces larger risks than the average proxy company. As such it should be placed above the midpoint for the proxy group. As noted above, Ibbotson finds that the required return for an entity in the mid-cap range is approximately 1.14% and the need to integrate generation, and its lower S&P credit rating, increases the cost of capital.

Q. What conclusions do you draw from the discussion above?

A. Because there is a link between capital structure[14] and the size premium[15] I formally adjust for the leverage, but do not adjust for the size albeit PGE should be placed at or above the midpoint for the sample.

[14] 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.
[15] Morningstar / Ibbotson, *SBBI 2014 Classic Yearbook*, p. 109.

III. Impact of the Economy and Markets on the Cost of Capital

Q. What do you cover in this section?

A. This section addresses the effect of the current economic situation and financial market conditions on the cost of capital. Specifically, this section addresses (i) how monetary policy has driven interest rates to historic lows and the plausible impact of a tapering of the policy on interest rates, (ii) the very large federal budget deficit and the potential impact on interest rates and inflation on a reduction in this deficit, and (iii) other factors that indicate how the current state of the economy and the industry impacts the cost of capital and the access to capital.

Q. Please summarize your view on interest rate developments.

A. The Federal Reserve (Fed) has been completing its tapering of its asset purchasing program. While the Fed purchases $75 billion worth of financial assets per month in January of 2014,[16] the figure was reduced to zero by the end of October 2014.[17] Although the Fed has finished its ongoing purchases, it must reduce its inventory of Treasury bonds and agency mortgage backed securities, which it accumulated in an effort to stimulate capital markets and keep interest rates low. The Fed's inventory of bonds increased from less than $869 billion in August 2007 to over $4 trillion at the end of 2013.[18] Unwinding this position will be a gradual process, and substantial effects of the taper on capital markets and interest rates

[16] Federal Reserve Bank of New York, "Statement Regarding Purchases of Treasury Securities and Agency Mortgage-Backed Securities," December 18, 2013.
[17] Federal Reserve Bank of New York. "Statement Regarding Purchases of Treasury Securities and Agency Mortgage-Backed Securities." October 29, 2014.
[18] *Bloomberg News*, "Fed Assets Reach Record $4 Trillion on Unprecedented Bond Buying," by Jeff Kearns, December 19, 2013. Available at:
http://www.bloomberg.com/news/articles/2013-12-19/fed-assets-reach-record-4-trillion-on-unprecedented-bond-buying

will not materialize overnight. However, it will eventually impact both access to capital and the cost. Furthermore, budget deficits at all levels of government are at high and unsustainable levels, and the potential exists for higher inflation as a result of deficit spending by the U.S. government and further liquidity injected into the capital markets by the Fed.

Q. What was the purpose of the Fed's asset purchases?

A. The Fed purchased bonds and other financial assets to stimulate the economy, reassure the capital markets, and keep interest rates low. The primary purpose of the asset purchase program was to drive down long-term interest rates, and in this regard it has been remarkably successful. The effectiveness of this policy is evidenced by the fact that U.S. Treasury Bond yields remain low by historical standards. Long-term and short-term interest rates were driven to historic lows[19] before beginning to increase with the start of tapering. The goal of the program was to spur economic activity by making it cheaper to borrow funds for new investment or to purchase durable assets such as houses and automobiles.

Q. What effects did the Fed's purchases have on equity and other markets?

A. During the crisis and its aftermath, the Fed's purchases supported the stock market by depressing the expected returns to bond investors. In times of economic uncertainty (such as the financial crisis), investors seek to reduce their exposure to market risk. This precipitates a so-called "flight to safety," 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

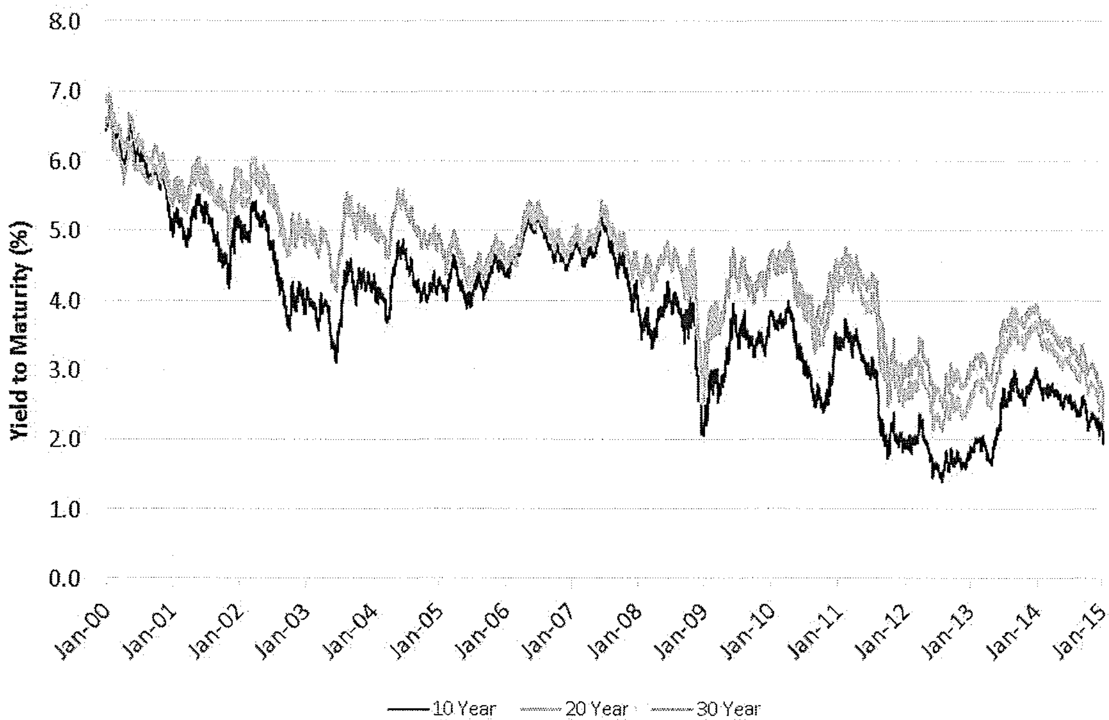
[19] See for example, the "long term stock, bond, interest rate and consumption data" provided at Professor Robert Shiller's website: http://www.econ.yale.edu/~shiller/data.htm

stocks, real estate, or gold or collectibles. Of course, all of these investments are riskier than government bonds, and investors still demand a risk premium (perhaps an especially high one in times of economic uncertainty) for investing in them. But short of accepting meager returns, investors simply have few alternatives to returning to the stock market. Thus, the Fed's bond purchases somewhat mitigate the effect of the "flight to safety" on equities and other investments. Utility stocks in particular benefit from this phenomenon because of their dividends. Emerging market countries benefited too, as investors sought higher returns.

Q. What has been the effect of the tapering during 2014?

A. Interest rates have increased since the possibility of tapering was first discussed in June 2013 (See Figure 2), but during 2014 and very early 2015, interest rates have declined slowly. Thus, while government bond yields have recovered somewhat from their historical lows in 2012 and early 2013, long-term U.S. treasury yields remain well below their pre-crisis and long-term average levels.

Figure 2: US Treasury Bond Yields from January 2000 – December 2014



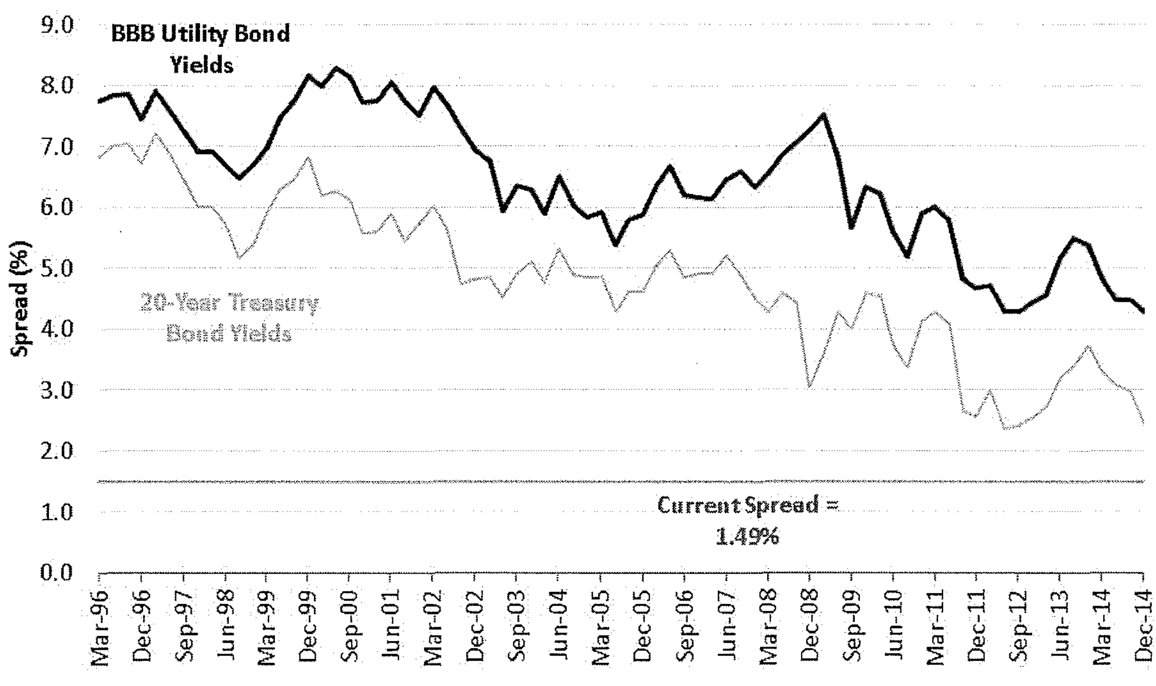
Source: Bloomberg as of January 7, 2014

Investor uncertainty is illustrated by the flow of funds into and out of mutual funds. (See Figures 5 and 6 below) Transfers out of bond mutual funds spiked when the Fed first discussed tapering, and stayed high through the end of 2013. This was likely driven by investors' expectations of rising interest rates, which would lead to falling bond prices. However, 2014 saw positive and increasing net flows into bond funds, reflecting a shift in expectations about interest rates: market participants are less convinced that rates will rise in the near term. Flows into equity mutual funds, meanwhile, have been somewhat erratic, with recent outflows suggesting that mutual fund investors may not have fully regained their appetite for risky stock investments.

Q. Has the yield spread between government and utility bonds changed since the start of the credit crisis?

A. Yes. Although the yield on utility bonds had declined somewhat from the height of the crisis (and has decreased since the start of the taper), it has been higher during most of the past two years than it was prior to the credit crisis. As shown in Figure 3 below, since the last major peak in November 2008 the spread between the yield on BBB-rated 20-year utility bonds and the yield on 20-year government bonds has ranged from a low of 133 basis points to a high of 418 basis points, compared to a 10-year historical average of approximately 150 basis points at that time.

Figure 3: Spread Between BBB Utility Bonds and 20-Year U.S. Treasury Bond Yields, January 1996 – December 2014



Source: Bloomberg as of January 7, 2014

Q. What is the implication of higher than normal yield spreads?

A. A higher than normal yield spread is one indication of the higher risk premium prevailing in the 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 normally the case, even for regulated utilities. Because debt is less risky than equity, this means that the cost of equity must also be higher relative to government bond yields than is usually observed. 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.

Q. Are the higher than normal yield spreads an indication of investors' "flight to safety"?

A. Yes. When investors become concerned about the economy, they frequently seek to reduce their exposure to investment risk. U.S. government debt is generally considered the least risky available investment—in effect it is regarded as the closest thing to a risk-free asset. Thus, U.S. government debt is in high demand during times of economic and political uncertainty. This implies in turn that the yields on U.S. government bonds are likely to be relatively lower during periods of economic and political turmoil. Moreover, the U.S. Fed's continued bond purchase programs have further increased the demand for medium- and long-term U.S. government bonds, thus depressing the yields on those bonds.

Q. What evidence can you provide that U.S. medium- and long-term government bond yields are currently depressed?

A. Over the past few years, the annual yields on long-term U.S. government bonds have dropped dramatically and remain depressed. For instance, the historical average of annual yields on long-term government bonds was 5.15% from 1926 through 2013, but long-term (20-year) government bond yields averaged 3.62% in 2011, 2.54% in 2012, 3.12% in 2013, and 3.07% 2014.[20] The slowing pace of the Fed's bond purchases and the recent outflows from bond funds has translated into a modest increase in bond yields but still well below the 15-year historical average of about 4.5%.[21]

Blue Chip Economic Indicators dated October 10, 2014 reports the consensus economic projections for the yield on 10-year U.S. Treasury notes to be 3.8% in 2016 and 4.2% in 2017. These consensus forecasts suggest that 10-year Treasury note yields will trend upward to 4.3% on average for 2016-2020 and 4.5% on average for 2021-2025.[22] These forecasts are substantially higher than the recent 2.1-2.4% yield on 10-year U.S. government bonds,[23] and highlight the fact that current long-term government bond yields are low both relative to historical levels, as well as compared to consensus forecasts of future rates. The currently depressed level of long-term government bond yields must be considered when evaluating the results of the risk-positioning model, because the downward bias in the long-term risk-free interest rate will inappropriately lower the sample companies' ROE estimates that would result, for example, from mechanically calculating the CAPM using current yields.

Q. Do regulated companies benefit from investors' flight to safety?

A. Yes, to some degree. Regulated companies are of lower relative risk than the average company in the market, and so investors may prefer to invest in them rather than in riskier companies during bad times. However, regardless of the type of investment, the required

[20] Bloomberg daily data for the 20-year government bond yield.
[21] *Ibid.* using data from 2000 to today.
[22] See *Blue Chip Economic Indicators*, dated October 10, 2014, page 14.
[23] As of December 9, 2014.

equity return is higher during periods of economic turmoil than otherwise because corporate and (especially) "risk free" government bonds are much less risky than equity, including utilities. This was demonstrated during the recent turmoil: prices of regulated companies fell along with the broader market. However, they did not fall as far (in percentage terms) as the market; this is as expected because regulated companies have lower risk than the market as a whole. Risk-positioning models predict that companies with lower betas, i.e., companies with lower risk relative to the market, will move with the market, but with lower volatility. The prices of regulated companies recovered faster than the market, in part because of the flight to safety, but have now been surpassed by the general market, again as expected according to the predictions of risk-positioning models.

Q. Why is it important to consider the stock market's volatility?

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, and 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.[24]

One implication of this finding is that the MRP tends to increase when market volatility is high, even when investors' level of risk aversion remains unchanged. Recently, market expectations for the volatility of the S&P 500 index have been quite close to their long-term

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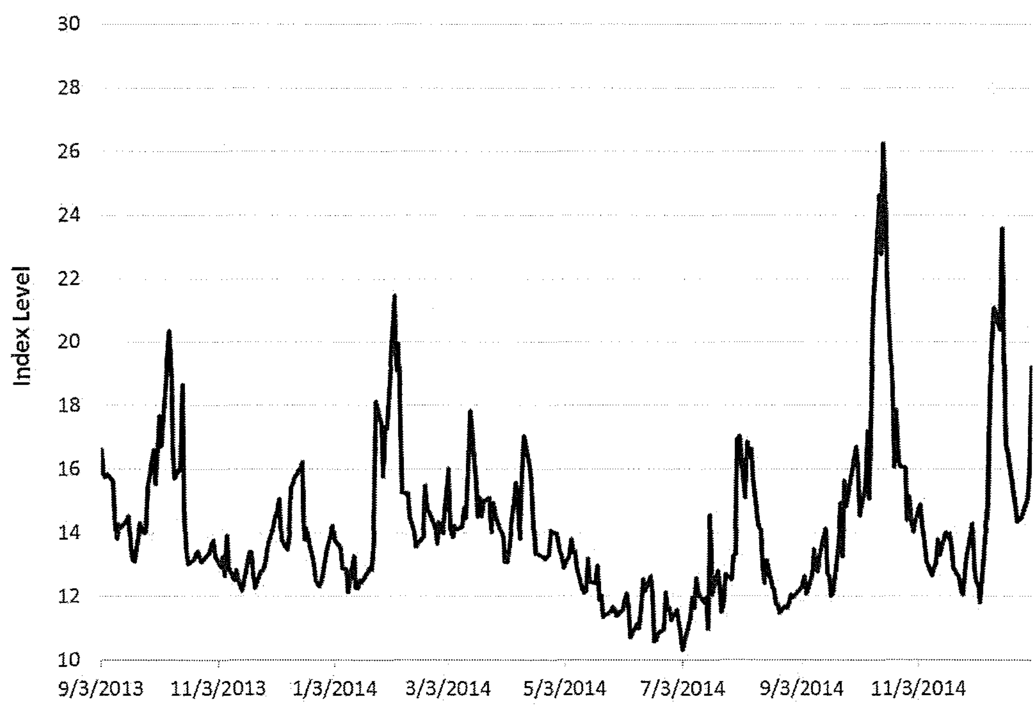
[24] K. French, W. Schwert and R. Stambaugh (1987), "Expected Stock Returns and Volatility," *Journal of Financial Economics*, Vol. 19, p. 3.

average of approximately 20%.[25] However, as seen in Figure 4 below, the variability in monthly stock market volatility has itself been quite high over the past year, with occasional spikes, indicating periods of increased uncertainty about likely market outcomes. For example, the Chicago Board Option Exchange Volatility Index (VIX) most recently increased above 25% on December 16, 2014 as both the Dow Jones and S&P 500 dropped more than 4%, oil prices declined, and the Russian currency declined relative to the U.S. dollar.[26]

Figure 4: VIX 09/2013-12/2014



Source: Bloomberg as of 1/5/2015

Q. What do you mean by the term "risk aversion"?

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[25] As measured by the CBOE Volatility Index (VIX), which measures market expectations for (annualized) 30-day volatility of the S&P 500 stock index based on implied volatility of options on the S&P 500. The average closing index value for the VIX from January 1, 2004 to December 31, 2014 was 19.62. Data pulled from Bloomberg as of 1/5/2015.

[26] YahooFinance.com; http://peterckenny.tumblr.com/post/105352024749/russian-ruble-collapse-fueled-by-global-petroleum.

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 crisis?

A. Yes. In response to the crisis, investors began allocating much larger shares of their portfolios to lower risk investments. In fact, many investors have left their investments in cash or low-yielding Treasuries rather than investing in stocks. For example, Figure 5 below compares monthly net new mutual fund flows into U.S. domestic equities versus total net flows into bonds. Figure 5 shows that net cash flows into domestic equities were predominantly negative from mid-2010 through the end of 2012, reaching almost $30 billion in outflows in July 2011. On the other hand, net flows into bonds were consistently positive throughout the crisis and its aftermath, with monthly inflows reaching nearly $35 billion at several points in 2012 and early 2013.

As discussed above, the latter trend reversed sharply in the second half of 2013—likely in response to the Fed's announcement in June 2013 regarding the tapering of its quantitative easing program.[27] This announcement led to a dramatic global bond sell-off, headlined by $60 billion in outflows from U.S. bond mutual funds as of June 2013.[28] Through the latter half of 2013, bond yields climbed as demand for bonds dipped,[29]

[27] "Fed message gets through to markets, sort of", Alister Bull, July 16, 2013, *Reuters*.
[28] *Ibid.*

[29] Bond yields rise when prices fall, since face value and coupon payments are fixed.

reflecting expectations that interest rates would finally rise after remaining so low for so long.

At the start of 2014, many traders held short positions in U.S. Treasury bonds effectively betting that government bond prices would fall as the interest rates rose in response to a growing economy. However, these expectations failed to materialize. Instead, the first eight months of 2014 saw a rally in bond buying (see Figure 2). By the end of December, Treasury yields were trading at their lowest levels since before the Fed's June 2013 tapering announcement.[30] This bond rally has surprised many market observers since U.S. economic indicators have shown modest improvement and most forecasters continue to expect higher interest rates in the medium term.[31] Nevertheless, investors who bet against bonds at the end of 2013 moved back into safe debt investments when predicted interest rate rises failed to materialize.

Additionally, U.S. Treasury bonds are especially appealing in 2014 when compared to European sovereign debt, for which yields are being driven down by slow economic growth and resulting monetary stimulus from the European Central Bank ("ECB") and more recently by the fear for another crisis in Greece. In June of 2014, the ECB made history by establishing a negative bank deposit rate — effectively charging banks money for depositing their money in the central bank.[32] Previously, banks were earning some, albeit small, interest on their funds kept at the central bank account. This accommodative stance by the ECB

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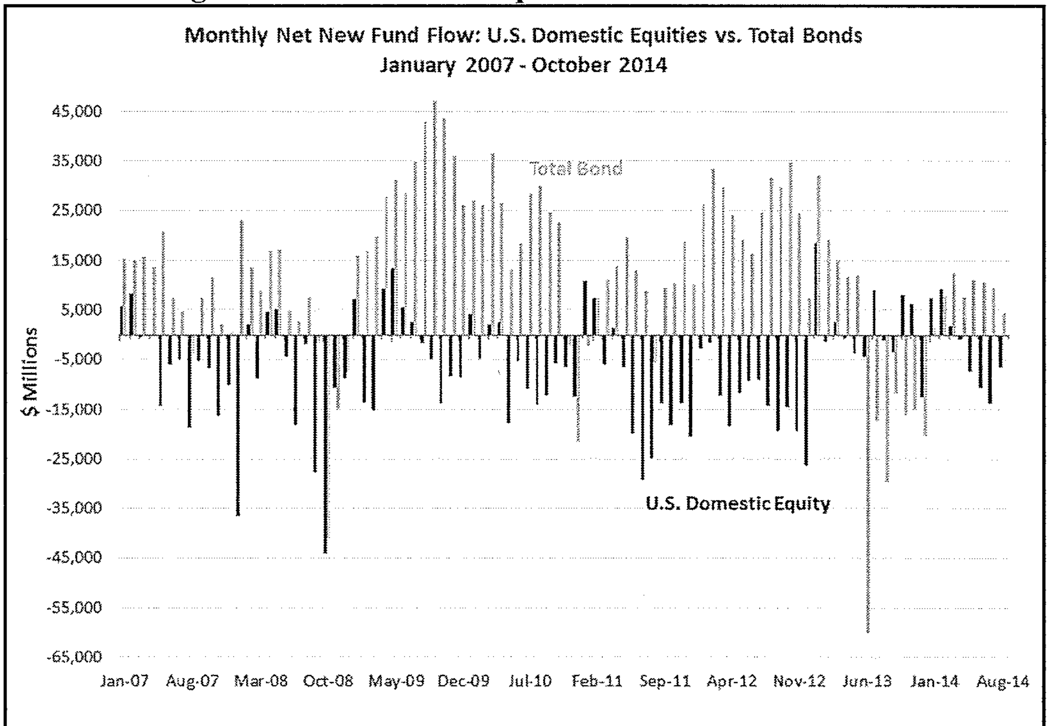
[30] Bloomberg LP, 10-Year, 20-Year and 30-Year U.S. Treasury bond Yields, accessed September 16, 2014.
[31] See, for example, Consensus Forecasts® September, 2014 survey, which predicts 10-Year Treasury bond yields will increase from 2.5% as of the survey to 3.4% by the end of September 2015.
[32] "ECB Unveils Rate Cuts, Lending Package", June 5, 2014, *The Wall Street Journal.* Available at:

http://www.wsj.com/articles/ecb-enters-uncharted-territory-with-rate-cuts-1401969463 reflects a low interest rate outlook for European markets, perhaps driving bond investors to seek potential upside in the U.S. debt market.

The U.S. stock market has generally performed well in 2013 and 2014, but the second half of 2014 saw significant ups and downs and the net flows for U.S. equity mutual funds have not exhibited a consistent trend. Although the uniform outflows observed in the early part of this decade have not occurred in the last couple of years, there is no clear indication in the data that investors are ready to move their money back into equities (i.e., a significant amount of investor funds are still placed in the bond market). Indeed, the short term trend of increasing outflows observed in the summer of 2014 (see Figure 5 and Figure 6 below) together with the increased demand for bonds suggests that a clear preference for lower-risk assets currently prevails in financial markets.

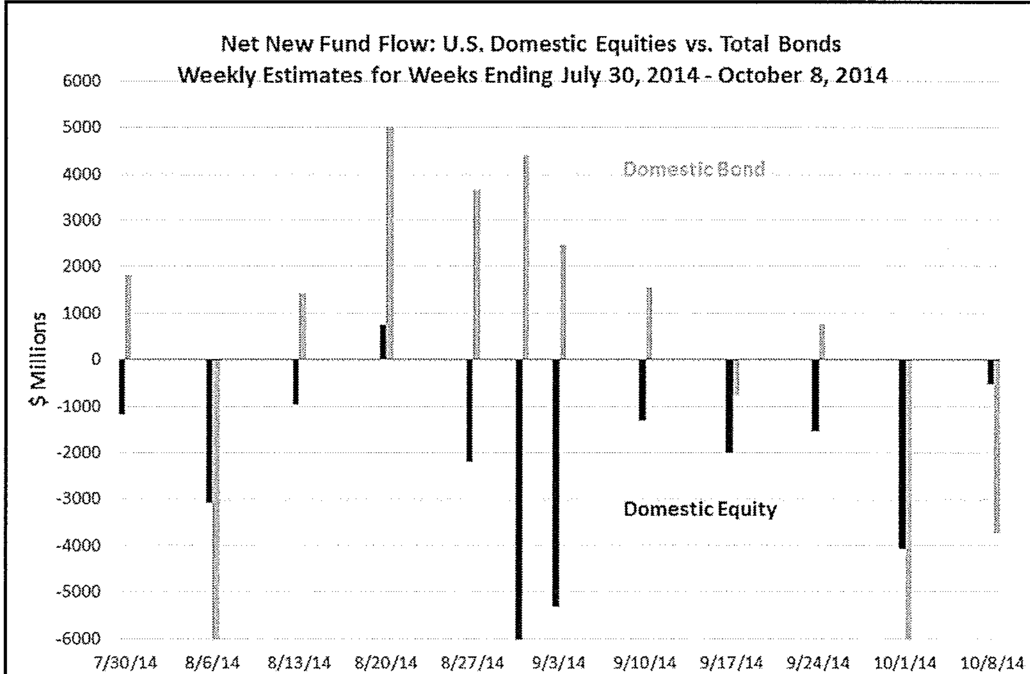
In general, these trends are consistent with the observation that the average investor's risk aversion remains elevated. Additionally, the particular set of circumstances leading to the current low bond yields may be a short-term phenomenon, suggesting that current yields may underestimate the long-term risk-free interest rate. As discussed in greater detail below and in PGE Exhibit 1103, a higher-than-normal equity risk premium and an underestimated risk-free rate may lead to a downward bias in cost of capital estimates that use the CAPM based or similar methods.

Figure 5: US Domestic Equities vs. Bonds 2007-2014.



Source: Investment Company Institute, accessed 10/15/2014.

Figure 6: Net New Funds Flow: US Domestic Equities vs. Bonds 2014, weekly



Source: Investment Company Institute, accessed 10/15/2014.

Q. Is the increase in the market risk premium a short-term or a long-term phenomenon?

A. I believe that it is a long-term phenomenon. Even when market conditions return to normal, investors' risk aversion is likely to remain higher until their confidence fully returns, which is likely to be well into the recovery period. A recent paper by Duarte and Rosa of the Federal Reserve of New York summarizes many forward-looking models of the required MRP and finds (illustrates) a very high MRP in recent years.

The authors estimate the MRP that results from a range of models each year from 1960 through 2013.[33] The authors then report the average as well as the 25- and 75-percentile of results. The authors find 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.[34] Similarly, Bloomberg estimates a higher than historical MRP in recent years – again indicating that it could be a while before investors' required premium returns to normal levels.

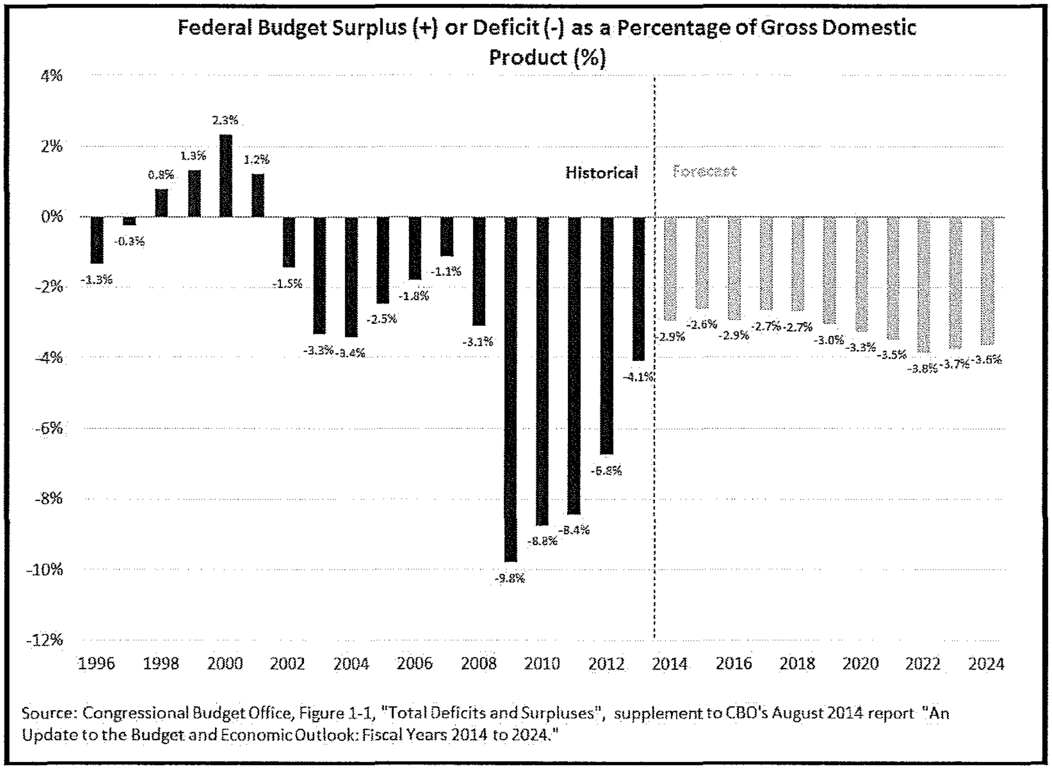
Q. What are your thoughts on the possible effect of the budget deficit on the economy?

A. In dollar terms, the federal budget deficit was $483 billion in fiscal year 2014 and $680 billion in 2013, down substantially from more than $1 trillion in fiscal year 2012.[35] This improvement may result partially from the budget sequestration that went into effect in early 2013. However, the 2013 fiscal year deficit was still approximately 50% higher than that of 2008 and well above the average level in the years leading up to the crisis. The U.S. Congressional Budget Office estimates that the budget deficit will represent approximately

[33] Fernando Duarte and Carlo Rosa, "The Equity Risk Premium: A Consensus of Models, " *Federal Reserve Bank of New York*, 2014 (Duarte & Rosa 2014).
[34] 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.
[35] Federal Reserve Bank of St. Louis, Economic Data, "Federal Surplus or Deficit," January 8, 2015.

3% of the Gross Domestic Product (GDP) in 2014 and will remain high relative to economic output over the foreseeable future (see Figure 7 below).[36]

Figure 7: Federal Budget Surplus or Deficit as a Percentage of Gross Domestic Product



Maintaining such a high deficit is unsustainable in the long run, especially if buyers of U.S. debt lose confidence in the U.S. economy and demand higher interest rates as compensation for the perceived higher risk. This suggests that going forward, the U.S. will have to be more fiscally conservative, and limit the stimulus funds it provides to the economy. Although inflation is not currently an issue, it is also quite likely that the magnitude of the federal budget deficit will affect U.S. inflation going forward. The Fed

[36] Congressional Budget Office: http://www.cbo.gov/.

now holds approximately $1,706 billion in mortgage-backed securities.[37] It is unclear how the unwinding of these positions will affect financial markets, which creates additional uncertainty.

Q. Are there recent events that have affected capital markets?

A. Yes. During the most recent 6-7 months, oil prices have declined substantially and the volatility inherent in these prices has increased significantly. While it is too early to determine the impact on the economy in general, it adds uncertainty to a key commodity and hence investor expectations.[38] The decline in oil prices, sanctions and possible other factors have significantly impacted oil-based economies, especially the Russian economy. In fact, S&P on January 26, 2015 downgraded Russia's foreign currency rating to junk.[39] Further, several developments in Europe have added to the economic uncertainty for investors. First, the Swiss National Bank has recently removed the cap on the Swiss franc versus the Euro, causing some trading firms significant losses and placing some non-Euro currencies under significant pressure.[40] Also, the recent general election in Greece has caused additional uncertainty regarding the future of the Euro and the status of loans granted to Greece.

Q. Please summarize how the economic developments discussed above have affected the return on equity and debt that investors require?

A. Companies such as PGE rely on investors in capital markets to support efficient business operations. These investors have been dramatically affected by the credit crisis, and while

[37] Federal Reserve Statistical Release as of September 25, 2014, available at http://www.federalreserve.gov/releases/h41/.
[38] PGE Exhibit 1107 shows the recent development in oil prices as well as the increase in the volatility inherent in oil prices. The volatility has more than doubled since the beginning of 2014.
[39] S&P, "Russia Foreign Currency Ratings Lowered to 'BB+/B'; Outlook Negative," January 26, 2015.
[40] For example, as of January 27, 2015 the interest rate on holding Danish kroner is negative at both State Street and Bank of New York Mellon. The Danish krone currently is pegged to the Euro. See, for example, http://www.slate.com/blogs/moneybox/2012/10/09/negative_interest_rates_for_swiss_francs_and_danish_krone_state_street_and_bank_of_new_york_mellon_go_less_than_zero_.html

there have been material improvements in capital markets and the macro-economy since the height of the financial crisis, there is evidence that investors' confidence remains low and their risk aversion remains elevated relative to pre-crisis periods.

Likewise, the effects of the federal budget deficit and the Fed's unwinding of its involvement in providing credit may have substantial but uncertain effects on the economy and financial markets. Finally, due to increased risk-aversion on the part of investors, as well as continued bond-purchase programs initiated by the Fed, long-term U.S. government bond yields (along with forecasts of future interest rates) have been pushed down to extremely low levels by historical standards. 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.

Q. Does your analysis consider the current economic conditions?

A. Yes. In implementing the CAPM and risk premium models, I rely on the estimated risk-free rate for the period when rates will be in effect rather than on the current risk-free rate. Further, the CAPM versions are based on the historical arithmetic MRP of 6.96%, whereas I in the past have relied on a range of figures below and above the historical estimate. The financial crisis and the current academic research have led me to believe that today's MRP cannot be less than the historical MRP. For simplicity and because the CAPM is not commonly used to determine the ROE before this Commission, I currently use only the historical arithmetic average as reported by Morningstar / Ibbotson. In addition, I present evidence on the forward looking MRP to ensure my estimate is consistent with investors' current view.

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.[41] This resulted in an initial group of 46 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 (e.g., substantial litigation).[42]

To estimate the cost of equity for the sample, I rely on two versions of the Discounted Cash Flow (DCF) model and three versions of the risk premium model. I further confirm

[41] The 46 companies are from Value Line Investment Analyzer, Accessed as of November 19, 2014.
[42] For example, I exclude both NextEra and Hawaiian Electric due to the recently announced acquisition of Hawaiian Electric by NextEra.

these figures by comparing the estimates to the recently allowed ROE for electric utilities and to estimates 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 three versions of the risk premium model using realized and authorized returns, respectively.

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 was 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, slightly higher relative risk as estimated by beta, and need to integrate substantial new generation in its portfolio.[43]

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 environmental expenditures, the 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.

[43] SNL Financial, "Company Report – Portland General Electric – Transitioning away from reliance on purchased power." December 19, 2014. While Portland General in the past has relied more heavily on Power Purchase Agreements than its peers, it has built substantial generation that will come online before or at the time the rates from this proceeding are expected to be in effect.

B. Sample Selection

Q. Please describe how you selected your sample.

A. To select a comparable sample of electric utilities, I began with the universe of publicly traded electric utilities as classified by Value Line.[44] This resulted in an initial group of 46 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.[45] 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 (e.g., substantial litigation). Value Line companies that merged as well as entities with an acquisition or merger larger than 30% of their market capitalization 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 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 29 electric utilities listed in Table 2 below.

The 2013 annual revenue as well as the market cap was obtained from Bloomberg as were the recent credit rating and growth estimate. Betas were obtained from Value Line.

[44] The 46 companies are from *Value Line Investment Analyzer*, Accessed as of November 19, 2014.
[45] *Edison Electric Institute*, Stock Performance - Q2 2014 Financial Update.

Table 2: Electric Sample and Its Characteristics[46]

Company	Regulated Assets	Market Cap. (3Q 2014) ($MM)	S&P Credit Rating (2013)	Long Term Growth Est	Value Line Betas
ALLETE	R	2,048	BBB+	6.0%	0.80
Alliant Energy	R	6,291	A-	5.8%	0.80
Amer. Elec. Power	R	25,812	BBB	4.8%	0.70
Ameren Corp.	R	9,318	BBB+	7.3%	0.75
CenterPoint Energy	MR	10,424	A-	6.0%	0.75
CMS Energy Corp.	R	8,161	BBB	6.0%	0.75
Consol. Edison	R	16,614	A-	5.5%	0.60
Dominion Resources	MR	40,119	A-	3.1%	0.70
DTE Energy	R	13,475	BBB+	5.3%	0.75
Edison Int'l	R	18,584	BBB+	4.0%	0.75
El Paso Electric	R	1,481	BBB	6.3%	0.70
Entergy Corp.	R	13,736	BBB	8.0%	0.70
G't Plains Energy	R	3,813	BBB+	4.5%	0.85
IDACORP Inc.	R	2,753	BBB	4.8%	0.80
MGE Energy	MR	1,340	AA-	3.7%	0.70
OGE Energy	R	7,266	A-	6.2%	0.85
Otter Tail Corp.	R	1,007	BBB	6.4%	0.95
PG&E Corp.	R	21,682	BBB	4.5%	0.65
Pinnacle West Capital	R	6,196	A-	5.7%	0.70
Portland General	R	2,567	BBB	4.2%	0.80
Public Serv. Enterprise	MR	18,979	BBB+	5.5%	0.75
SCANA Corp.	MR	7,105	BBB+	7.0%	0.75
Sempra Energy	MR	25,772	BBB+	3.7%	0.75
Southern Co.	R	39,217	A	4.0%	0.60
Vectren Corp.	MR	3,336	A-	6.9%	0.80
Westar Energy	R	4,550	BBB+	4.5%	0.75
Xcel Energy Inc.	R	15,664	A-	6.3%	0.70

Notes: R – Regulated (at least 80% of assets are regulated), MR (50-79% of assets are regulated).

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 as is PGE. The 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).

[46] Sources: *Value Line Investment Survey* as of December 9, 2014, Bloomberg as of December 9, 2014, and *Edison Electric Institute* as of December 9, 2014.

The majority of the companies are materially larger than PGE and only four companies have a market cap below that of PGE, while 19 companies have a market cap that exceeds twice that of PGE. Measured by beta, a measure of systematic risk, PGE is in the upper end of the sample, but its growth rate was slightly lower. However, the equity analysts that submit forecasts to Institutional Brokers Estimate System (IBES) as of year-end had increased PGE's growth rate to 7.97%.[47] Thus, PGE's systematic risk, size, and some growth rate sources indicate that PGE has a higher cost of equity than the comparable sample.

C. Capital Structure

Q. What regulatory capital structure has PGE requesting in this proceeding?

A. PGE has proposed a regulatory capital structure consisting of 50% equity and 50% debt,[48] which was the capital structure approved in the recent UE 283 proceeding.[49] This capital structure is broadly consistent with the book value capital structures of the sample companies. The sample averages about 48% equity on a book basis. The highest percentage of book equity for the companies in the sample is 61% equity (MGE Energy Inc.) and the lowest is 31% equity (CMS Energy Corp.).[50] However, the market based estimates of the cost of equity for the DCF (and CAPM) are based on the market value capital structure which includes approximately 61% equity as of November 2014 and averaged approximately 55% equity over the last five years. 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.

[47] IBES data from Yahoo Finance, December 31, 2014.
[48] The calculation of the capital structure is available in PGE Exhibit 1100, Hager – Valach – Greene, p. 22.
[49] Order 14-442, issued December 4, 2014, p. 3.
[50] See PGE Exhibit 1105.

V. Cost of Capital Estimates

Q. How do you estimate the sample companies' costs of equity?

A. As noted earlier, I implement 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 the Office of Management and Budget (The White House) and Blue Chip. Further, I estimate the ROE from three versions of the risk premium method: a regression analysis of allowed return on bond rates and a traditional look at earned and allowed ROE over treasuries. Finally, I estimate two versions of the CAPM as a check on my results: the traditional CAPM and two versions of the Empirical CAPM.[51] 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.

[51] 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:

$$P = \frac{D_1}{(1+r)} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \qquad (2)$$

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,

$$P = \frac{D_1}{(r - g)} \qquad (3)$$

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 (v-1) that can be solved to yield the well-known "DCF formula" for the cost of capital:

$$\begin{aligned} r &= \frac{D_1}{P} + g \\ &= \frac{D_0 \times (1+g)}{P} + g \end{aligned} \qquad (4)$$

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).[52] One such alternative expands the Gordon DCF model to three stages.[53] 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

[52] 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.

[53] 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 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.[54]

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.

[54] Blue Chip Economic Indicators, October 10, 2014 and the Fiscal Year 2015 Budget Forecast, March 2014. The latter has in the past been one of the estimates relied upon by Commission Staff.

Q. Does the multistage DCF improve upon the simple DCF?

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. The ROE estimate is 11.2% for the Gordon (single-stage) DCF model, and 9.8% and 10.0% for the multistage model using the Blue Chip long term GDP growth rate forecast, or the average of the Blue Chip and OMB forecasts, respectively.

Table 3: DCF Estimates on the Cost of Equity

	DCF		
	Simple	Multi-stage using forecasted GDP growth rate from Blue Chip	Multi-stage using average forecasted GDP growth rate from Blue Chip and OMB
Cost of Equity	11.2%	9.8%	10.0%

Q. What conclusions do you draw from the DCF analysis?

A. The estimate from the multi-stage model using a combined Blue Chip and OMB growth rate is consistent with recently allowed ROE for electric utilities, where the average without

Virginia specific generation incentive returns and without distribution only utilities is 10.0% for 2014. Further, the range and average are consistent with my point estimate of 10.25% and the multi-stage estimates supports PGE's requested ROE of 9.9%.

B. Risk Premium Methods

Q. Do you estimate the Cost of Equity that result from risk premium analyses?

A. Yes, I estimate three versions of the risk premium cost of equity. First, 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 10-year government bond rate using quarterly data. This results in an estimated ROE of 10.7% for 2016-17. Second, I calculate the difference between the earned return on equity for electric utilities and the 10-year government bond yield. This results in a risk premium over the 20-year government bond yield. I add the forecasted 20-year government bond yield to the estimated risk premium to calculate a cost of equity of 10.6% for 2016-17. As a test on my regression analysis I also calculate the risk premium that has been granted by state regulatory commissions since 1997. Adding the forecasted risk-free rate to the historical risk premium of 6.37% for 1997-2014 (Q3), I find an ROE estimate of 10.0%.

Q. Please explain the implementation and data underlying your first risk premium analysis.

A. Using quarterly data from Regulatory Research Associates from Q1 1990 to Q3 2014,[55] I estimate the equation:

$$\text{Risk Premium} = A_0 + A_1 \times (\text{Treasury Bond Yield}) \qquad (5)$$

[55] SNL Financial as of December 3, 2014.

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 6.37%, which when added to the forecasted 10-year yield in 2016-17 as PGE's rates are expected to be in effect over that period. As the forecasted 10-year yield average 4.64% for 2016-17,[56] I obtain a cost of equity estimate of 10.7%. As a check on this result, I also calculate the risk premium over the 1997 to 2014 period, which results in an ROE estimate of 10.6%. I used the period 1997 to today for this analysis because the FERC issued Rule 888 in 1996 and thereby made electric deregulation feasible. Subsequently, some states deregulated electric markets. It is plausible that deregulation had a substantial effect on electric utilities in deregulated markets, so I excluded the period prior to deregulation.

Q. What are the details of the last risk premium analysis?

A. Using data from Bloomberg,[57] I obtain the average annual return on equity earned by the electric utilities in my sample from 1997 to 2013.[58] I subtract the average annual yield on 20-year Treasury bonds from the earned equity return to obtain the risk premium. Using an average over the full period, I estimate a risk premium of 6.37%. I add the estimated risk premium to the forecasted yield on 20-year government bonds to obtain an estimated ROE of 10%.[59]

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[56] *Blue Chip Economic Indicators Forecast*, October 16, 2014.
[57] SNL Financial as of December 3, 2014.
[58] Regulatory Research Associates, "Major Rate Case Decisions – January-September 2014," October 10, 2014.
[59] See PGE Exhibit 1102 for details.

Q. Are these estimates consistent with PGE's regulatory capital structure of 50% equity and 50% debt?

A. Yes, the allowed 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.[60] Therefore, the estimated ROE is consistent with PGE's capital structure.

Q. Please summarize the results from your risk premium analyses.

A. The results from my risk premium analyses are summarized in Table 4 below.

Table 4: Cost of Equity Estimates from Risk Premium Analyses

	Estimated ROE
Regression Analysis	10.7%
Premium over Allowed ROE	10.0%
Premium over Earned ROE	10.6%

Q. What conclusions do you draw from these analyses?

A. The three risk premium analyses confirm the range I have obtained from other analyses and makes clear that PGE's request for an ROE of 9.9% on 50% equity is reasonable and conservative, as the range is above PGE's requested ROE of 9.9%.

Q. Is there other relevant evidence regarding the current cost of equity for electric utilities?

A. Yes, looking at the recently allowed ROE for regulated electric utilities, I find that the recent evidence is consistent with an average allowed ROE of about 10%. This figure is consistent

[60] Regulatory Research Associates, "Major Rate Case Decisions – January-September 2014," October 10, 2014, p. 4.

the average allowed ROE for all electric utilities as well as with the average when Virginia's generation incentive ROEs as well as distribution only ROE are excluded.[61] Finally, I estimate the cost of equity using the Capital Asset Pricing Model, which determines the cost of equity as follows:

$$r_S = r_f + \beta_S \times MRP \tag{6}$$

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 forecast for 2016-17 (as in the risk-premium analyses above), and the historical MRP for the period 1926-2013 as reported by the 2014 Duff & Phelps Valuation Handbook.[62] 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 9.8% to 10.2%, which confirms that PGE's requested ROE of 9.9% is reasonable. The details of this model are in PGE Exhibits 1103 and 1104.

[61] Source: SNL Energy. See PGE Exhibit 1105 for details.
[62] *Blue Chip Economic Indicators*, October 10, 2014; Duff & Phelps, 2014 Valuation Handbook, Exhibit 3-6.

VI. Conclusion

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 10.0% to 10.7% ignoring the lowest and highest estimate, so that a point estimate of 10.25% is reasonable. The overall range is wider, 9.8% to 11.2%, and includes PGE's requested ROE of 9.9%. This range is also consistent with the recently allowed ROE for U.S. electric utilities. Because PGE is smaller than the average sample company and a higher systematic risk, I believe a range of 10.0% to 10.7% is more appropriate.

Overall, I believe PGE's request for an ROE of 9.9% is reasonable and a bit conservative.

VII. Qualification

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.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1101	DCF Model
1102	Risk Premium Model
1103	The CAPM Description
1104	The CAPM Estimates
1105	Authorized ROE and Capital Structure 2000-2014
1106	Equity Premiums
1107	Dynamics of Oil Prices

Table 3
DCF Return on Equity Summary

	DCF		
	Simple	Multi-stage using forecasted GDP growth rate from Blue Chip	Multi-stage using average forecasted GDP growth rate from Blue Chip and OMB
Cost of Equity	11.2%	9.8%	10.0%

DCF Cost of Equity of the 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	$51.29	$0.49	0.97%	7.0%	1.7%	11.2%
Alliant Energy	$63.11	$0.51	0.82%	5.3%	1.3%	8.8%
Amer. Elec. Power	$57.70	$0.53	0.93%	5.2%	1.3%	9.1%
Ameren Corp.	$42.82	$0.41	0.98%	7.6%	1.8%	11.8%
CenterPoint Energy	$24.01	$0.24	1.01%	6.7%	1.6%	11.0%
CMS Energy Corp.	$33.14	$0.27	0.83%	6.4%	1.6%	9.9%
Consol. Edison	$63.07	$0.63	1.01%	3.0%	0.7%	7.2%
Dominion Resources	$72.37	$0.60	0.84%	5.9%	1.5%	9.5%
DTE Energy	$81.60	$0.69	0.86%	5.2%	1.3%	8.8%
Edison Int'l	$63.34	$0.36	0.57%	5.4%	1.3%	7.8%
El Paso Electric	$37.99	$0.28	0.75%	6.3%	1.5%	9.5%
Entergy Corp.	$83.06	$0.83	1.00%	1.6%	0.4%	5.7%
G't Plains Energy	$26.35	$0.25	0.94%	5.3%	1.3%	9.3%
IDACORP Inc.	$62.30	$0.47	0.76%	2.5%	0.6%	5.7%
MGE Energy	$44.35	$0.28	0.65%	6.0%	1.5%	8.7%
OGE Energy	$36.08	$0.25	0.70%	6.3%	1.5%	9.2%
Otter Tail Corp.	$29.14	$0.30	1.06%	7.5%	1.8%	12.1%
PG&E Corp.	$50.58	$0.46	0.92%	8.6%	2.1%	12.6%
Pinnacle West Capital	$63.76	$0.60	0.94%	4.4%	1.1%	8.3%
Portland General	$36.87	$0.28	0.77%	6.2%	1.5%	9.5%
Public Serv. Enterprise	$40.75	$0.37	0.92%	4.2%	1.0%	8.1%
SCANA Corp.	$56.50	$0.53	0.94%	5.6%	1.4%	9.5%
Sempra Energy	$110.49	$0.66	0.61%	8.6%	2.1%	11.2%
Southern Co.	$47.43	$0.53	1.12%	3.9%	1.0%	8.6%
Vectren Corp.	$44.47	$0.38	0.87%	7.5%	1.8%	11.2%
Westar Energy	$38.84	$0.35	0.91%	4.7%	1.1%	8.5%
Xcel Energy Inc.	$34.11	$0.30	0.89%	5.6%	1.4%	9.3%

Sources and Notes:
[1]: Workpaper #1 to Exhibit 1101 - B.
[2]: Workpaper #2 to Exhibit 1101 - B.
[3]: [2] / [1] x (1 + [5]).
[4]: Supplementary Exhibit 4, [6].
[5]: {(1 + [4]) ^ (1/4)} - 1.
[6]: {([3] + [5] + 1) ^ 4} - 1.

DCF Cost of Equity of the Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	Stock Price [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	$51.29	$0.49	7.0%	6.6%	6.3%	5.9%	5.5%	5.1%	4.7%	9.4%
Alliant Energy	$63.11	$0.51	5.3%	5.2%	5.1%	5.0%	4.9%	4.8%	4.7%	8.3%
Amer. Elec. Power	$57.70	$0.53	5.2%	5.1%	5.0%	4.9%	4.9%	4.8%	4.7%	8.7%
Ameren Corp.	$42.82	$0.41	7.6%	7.1%	6.6%	6.1%	5.7%	5.2%	4.7%	9.6%
CenterPoint Energy	$24.01	$0.24	6.7%	6.4%	6.1%	5.7%	5.4%	5.0%	4.7%	9.5%
CMS Energy Corp.	$33.14	$0.27	6.4%	6.1%	5.8%	5.5%	5.3%	5.0%	4.7%	8.5%
Consol. Edison	$63.07	$0.63	3.0%	3.3%	3.6%	3.9%	4.1%	4.4%	4.7%	8.5%
Dominion Resources	$72.37	$0.60	5.9%	5.7%	5.5%	5.3%	5.1%	4.9%	4.7%	8.5%
DTE Energy	$81.60	$0.69	5.2%	5.1%	5.1%	5.0%	4.9%	4.8%	4.7%	8.4%
Edison Int'l	$63.34	$0.36	5.4%	5.3%	5.2%	5.0%	4.9%	4.8%	4.7%	7.2%
El Paso Electric	$37.99	$0.28	6.3%	6.0%	5.8%	5.5%	5.2%	5.0%	4.7%	8.2%
Entergy Corp.	$83.06	$0.83	1.6%	2.1%	2.6%	3.1%	3.7%	4.2%	4.7%	8.2%
G't Plains Energy	$26.35	$0.25	5.3%	5.2%	5.1%	5.0%	4.9%	4.8%	4.7%	8.8%
IDACORP Inc.	$62.30	$0.47	2.5%	2.9%	3.3%	3.6%	4.0%	4.3%	4.7%	7.5%
MGE Energy	$44.35	$0.28	6.0%	5.8%	5.6%	5.4%	5.1%	4.9%	4.7%	7.6%
OGE Energy	$36.08	$0.25	6.3%	6.0%	5.7%	5.5%	5.2%	5.0%	4.7%	7.9%
Otter Tail Corp.	$29.14	$0.30	7.5%	7.1%	6.6%	6.1%	5.6%	5.2%	4.7%	9.9%
PG&E Corp.	$50.58	$0.46	8.6%	7.9%	7.3%	6.6%	6.0%	5.3%	4.7%	9.5%
Pinnacle West Capital	$63.76	$0.60	4.4%	4.4%	4.5%	4.5%	4.6%	4.6%	4.7%	8.6%
Portland General	$36.87	$0.28	6.2%	6.0%	5.7%	5.5%	5.2%	5.0%	4.7%	8.2%
Public Serv. Enterprise	$40.75	$0.37	4.2%	4.3%	4.4%	4.5%	4.5%	4.6%	4.7%	8.4%
SCANA Corp.	$56.50	$0.53	5.6%	5.4%	5.3%	5.1%	5.0%	4.8%	4.7%	8.9%
Sempra Energy	$110.49	$0.66	8.6%	7.9%	7.3%	6.6%	6.0%	5.3%	4.7%	7.9%
Southern Co.	$47.43	$0.53	3.9%	4.1%	4.2%	4.3%	4.4%	4.6%	4.7%	9.2%
Vectren Corp.	$44.47	$0.38	7.5%	7.0%	6.6%	6.1%	5.6%	5.2%	4.7%	9.0%
Westar Energy	$38.84	$0.35	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	8.5%
Xcel Energy Inc.	$34.11	$0.30	5.6%	5.4%	5.3%	5.1%	5.0%	4.8%	4.7%	8.6%

Sources and Notes:
[1]: Workpaper #1 to Exhibit 1101 - B.
[2]: Workpaper #2 to Exhibit 1101 - B.
[3]: Supplementary Exhibit 4, [6].
[4]: [3] - {([3] - [9])/ 6}.
[5]: [4] - {([3] - [9])/ 6}.
[6]: [5] - {([3] - [9])/ 6}.
[7]: [6] - {([3] - [9])/ 6}.
[8]: [7] - {([3] - [9])/ 6}.
[9]: BlueChip Economic Indicators, October 2014 (U.S.), 2015-2020 average long term growth rate This number is assumed to be the perpetual growth rate.
[10]: Workpaper #3 to Exhibit 1101 - B.

DCF Cost of Equity of the Electric Sample

Panel C: Multi-Stage DCF (Using average of Blue Chip and OMB Long-Term GDP Growth Forecasts 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	$51.29	$0.49	7.0%	6.7%	6.3%	5.9%	5.6%	5.2%	4.8%	9.5%
Alliant Energy	$63.11	$0.51	5.3%	5.2%	5.2%	5.1%	5.0%	4.9%	4.8%	8.4%
Amer. Elec. Power	$57.70	$0.53	5.2%	5.1%	5.1%	5.0%	4.9%	4.9%	4.8%	8.8%
Ameren Corp.	$42.82	$0.41	7.6%	7.1%	6.7%	6.2%	5.8%	5.3%	4.8%	9.7%
CenterPoint Energy	$24.01	$0.24	6.7%	6.4%	6.1%	5.8%	5.5%	5.1%	4.8%	9.6%
CMS Energy Corp.	$33.14	$0.27	6.4%	6.1%	5.9%	5.6%	5.4%	5.1%	4.8%	8.7%
Consol. Edison	$63.07	$0.63	3.0%	3.3%	3.6%	3.9%	4.2%	4.5%	4.8%	8.6%
Dominion Resources	$72.37	$0.60	5.9%	5.8%	5.6%	5.4%	5.2%	5.0%	4.8%	8.6%
DTE Energy	$81.60	$0.69	5.2%	5.2%	5.1%	5.0%	5.0%	4.9%	4.8%	8.5%
Edison Int'l	$63.34	$0.36	5.4%	5.3%	5.2%	5.1%	5.0%	4.9%	4.8%	7.3%
El Paso Electric	$37.99	$0.28	6.3%	6.1%	5.8%	5.6%	5.3%	5.1%	4.8%	8.3%
Entergy Corp.	$83.06	$0.83	1.6%	2.1%	2.7%	3.2%	3.7%	4.3%	4.8%	8.3%
G't Plains Energy	$26.35	$0.25	5.3%	5.2%	5.1%	5.1%	5.0%	4.9%	4.8%	8.9%
IDACORP Inc.	$62.30	$0.47	2.5%	2.9%	3.3%	3.7%	4.1%	4.4%	4.8%	7.6%
MGE Energy	$44.35	$0.28	6.0%	5.8%	5.6%	5.4%	5.2%	5.0%	4.8%	7.7%
OGE Energy	$36.08	$0.25	6.3%	6.0%	5.8%	5.5%	5.3%	5.1%	4.8%	8.1%
Otter Tail Corp.	$29.14	$0.30	7.5%	7.1%	6.6%	6.2%	5.7%	5.3%	4.8%	10.0%
PG&E Corp.	$50.58	$0.46	8.6%	8.0%	7.3%	6.7%	6.1%	5.5%	4.8%	9.6%
Pinnacle West Capital	$63.76	$0.60	4.4%	4.5%	4.5%	4.6%	4.7%	4.8%	4.8%	8.7%
Portland General	$36.87	$0.28	6.2%	6.0%	5.8%	5.5%	5.3%	5.1%	4.8%	8.4%
Public Serv. Enterprise	$40.75	$0.37	4.2%	4.3%	4.4%	4.5%	4.6%	4.7%	4.8%	8.6%
SCANA Corp.	$56.50	$0.53	5.6%	5.4%	5.3%	5.2%	5.1%	5.0%	4.8%	9.0%
Sempra Energy	$110.49	$0.66	8.6%	8.0%	7.3%	6.7%	6.1%	5.5%	4.8%	8.0%
Southern Co.	$47.43	$0.53	3.9%	4.1%	4.2%	4.4%	4.5%	4.7%	4.8%	9.3%
Vectren Corp.	$44.47	$0.38	7.5%	7.1%	6.6%	6.2%	5.7%	5.3%	4.8%	9.1%
Westar Energy	$38.84	$0.35	4.7%	4.7%	4.7%	4.8%	4.8%	4.8%	4.8%	8.6%
Xcel Energy Inc.	$34.11	$0.30	5.6%	5.5%	5.3%	5.2%	5.1%	5.0%	4.8%	8.8%

Sources and Notes:
[1]: Workpaper #1 to Exhibit 1101 - B.
[2]: Workpaper #2 to Exhibit 1101 - B.
[3]: Supplementary Exhibit 4, [6].
[4]: [3] - {([3] - [9])/ 6}.
[5]: [4] - {([3] - [9])/ 6}.
[6]: [5] - {([3] - [9])/ 6}.
[7]: [6] - {([3] - [9])/ 6}.
[8]: [7] - {([3] - [9])/ 6}.
[9]: BlueChip Economic Indicators, October 2014 (U.S.), 2015-2020 average long term growth rate combined with OMB estimates. This number is assumed to be the perpetual growth rate.
[10]: Workpaper #3 to Exhibit 1101 - B.

Overall After-Tax DCF Cost of Capital of the Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	3rd Quarter, 2014 Bond Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	Portland General's Income Tax Rate	Overall After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
ALLETE	BBB	11.2%	0.62	-	0.00	4.5%	0.38	39.9%	8.0%
Alliant Energy	A	8.8%	0.63	4.1%	0.02	4.1%	0.35	39.9%	6.4%
Amer. Elec. Power	BBB	9.1%	0.58	-	0.00	4.5%	0.42	39.9%	6.4%
Ameren Corp.	BBB	11.8%	0.61	-	0.00	4.5%	0.39	39.9%	8.3%
CenterPoint Energy	A	11.0%	0.53	-	0.00	4.1%	0.47	39.9%	7.0%
CMS Energy Corp.	BBB	9.9%	0.49	-	0.00	4.5%	0.51	39.9%	6.2%
Consol. Edison	A	7.2%	0.60	-	0.00	4.1%	0.40	39.9%	5.3%
Dominion Resources	A	9.5%	0.63	4.1%	0.00	4.1%	0.36	39.9%	6.9%
DTE Energy	BBB	8.8%	0.63	-	0.00	4.5%	0.37	39.9%	6.5%
Edison Int'l	BBB	7.8%	0.59	4.5%	0.06	4.5%	0.35	39.9%	5.8%
El Paso Electric	BBB	9.5%	0.59	-	0.00	4.5%	0.41	39.9%	6.7%
Entergy Corp.	BBB	5.7%	0.54	4.5%	0.01	4.5%	0.45	39.9%	~~4.3%~~
G't Plains Energy	BBB	9.3%	0.51	4.5%	0.00	4.5%	0.49	39.9%	6.1%
IDACORP Inc.	BBB	5.7%	0.66	-	0.00	4.5%	0.34	39.9%	~~4.7%~~
MGE Energy	AA	8.7%	0.78	-	0.00	3.9%	0.22	39.9%	7.3%
OGE Energy	A	9.2%	0.71	-	0.00	4.1%	0.29	39.9%	7.3%
Otter Tail Corp.	BBB	12.1%	0.67	-	0.00	4.5%	0.33	39.9%	8.9%
PG&E Corp.	BBB	12.6%	0.60	4.5%	0.01	4.5%	0.39	39.9%	8.6%
Pinnacle West Capital	A	8.3%	0.66	-	0.00	4.1%	0.34	39.9%	6.3%
Portland General	BBB	9.5%	0.54	-	0.00	4.5%	0.46	39.9%	6.3%
Public Serv. Enterprise	BBB	8.1%	0.69	-	0.00	4.5%	0.31	39.9%	6.4%
SCANA Corp.	BBB	9.5%	0.56	-	0.00	4.5%	0.44	39.9%	6.5%
Sempra Energy	BBB	11.2%	0.67	4.5%	0.00	4.5%	0.33	39.9%	8.4%
Southern Co.	A	8.6%	0.62	4.1%	0.02	4.1%	0.36	39.9%	6.3%
Vectren Corp.	A	11.2%	0.69	-	0.00	4.1%	0.31	39.9%	8.5%
Westar Energy	BBB	8.5%	0.58	-	0.00	4.5%	0.42	39.9%	6.1%
Xcel Energy Inc.	A	9.3%	0.58	-	0.00	4.1%	0.42	39.9%	6.4%
Simple Full Sample Average		9.6%	0.61	4.3%	0.00	4.3%	0.38	39.9%	6.9%

Sources and Notes:
[1]: S&P Rating as of December 9, 2014.
[2]: Exhibit 1101 - B; Panel A, [6].
[3]: Supplementary Exhibit 3, [1].
[4]: Workpaper #2 to Table 2, Panel C.
[5]: Supplementary Exhibit 3, [2].
[6]: Workpaper #2 to Table 2, Panel B.
[7]: Supplementary Exhibit 3, [3].
[8]: Provided by Portland General.
[9]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

Overall After-Tax DCF Cost of Capital of the Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	3rd Quarter, 2014 Bond Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	Portland General's Income Tax Rate	Overall After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
ALLETE	BBB	9.4%	0.62	-	0.00	4.5%	0.38	39.9%	6.8%
Alliant Energy	A	8.3%	0.63	4.1%	0.02	4.1%	0.35	39.9%	6.1%
Amer. Elec. Power	BBB	8.7%	0.58	-	0.00	4.5%	0.42	39.9%	6.2%
Ameren Corp.	BBB	9.6%	0.61	-	0.00	4.5%	0.39	39.9%	6.9%
CenterPoint Energy	A	9.5%	0.53	-	0.00	4.1%	0.47	39.9%	6.2%
CMS Energy Corp.	BBB	8.5%	0.49	-	0.00	4.5%	0.51	39.9%	5.5%
Consol. Edison	A	8.5%	0.60	-	0.00	4.1%	0.40	39.9%	6.1%
Dominion Resources	A	8.5%	0.63	4.1%	0.00	4.1%	0.36	39.9%	6.3%
DTE Energy	BBB	8.4%	0.63	-	0.00	4.5%	0.37	39.9%	6.3%
Edison Int'l	BBB	7.2%	0.59	4.5%	0.06	4.5%	0.35	39.9%	5.5%
El Paso Electric	BBB	8.2%	0.59	-	0.00	4.5%	0.41	39.9%	5.9%
Entergy Corp.	BBB	8.2%	0.54	4.5%	0.01	4.5%	0.45	39.9%	5.6%
G't Plains Energy	BBB	8.8%	0.51	4.5%	0.00	4.5%	0.49	39.9%	5.8%
IDACORP Inc.	BBB	7.5%	0.66	-	0.00	4.5%	0.34	39.9%	5.9%
MGE Energy	AA	7.6%	0.78	-	0.00	3.9%	0.22	39.9%	6.5%
OGE Energy	A	7.9%	0.71	-	0.00	4.1%	0.29	39.9%	6.4%
Otter Tail Corp.	BBB	9.9%	0.67	-	0.00	4.5%	0.33	39.9%	7.5%
PG&E Corp.	BBB	9.5%	0.60	4.5%	0.01	4.5%	0.39	39.9%	6.8%
Pinnacle West Capital	A	8.6%	0.66	-	0.00	4.1%	0.34	39.9%	6.5%
Portland General	BBB	8.2%	0.54	-	0.00	4.5%	0.46	39.9%	5.7%
Public Serv. Enterprise	BBB	8.4%	0.69	-	0.00	4.5%	0.31	39.9%	6.6%
SCANA Corp.	BBB	8.9%	0.56	-	0.00	4.5%	0.44	39.9%	6.1%
Sempra Energy	BBB	7.9%	0.67	4.5%	0.00	4.5%	0.33	39.9%	6.2%
Southern Co.	A	9.2%	0.62	4.1%	0.02	4.1%	0.36	39.9%	6.7%
Vectren Corp.	A	9.0%	0.69	-	0.00	4.1%	0.31	39.9%	7.0%
Westar Energy	BBB	8.5%	0.58	-	0.00	4.5%	0.42	39.9%	6.1%
Xcel Energy Inc.	A	8.6%	0.58	-	0.00	4.1%	0.42	39.9%	6.0%
Multi Full Sample Average		8.6%	0.61	4.3%	0.00	4.3%	0.38	39.9%	6.3%

Sources and Notes:

[1]: S&P Rating as of December 9, 2014.
[2]: Exhibit 1101 - B; Panel B, [10].
[3]: Supplementary Exhibit 3, [1].
[4]: Workpaper #2 to Table 2, Panel C.
[5]: Supplementary Exhibit 3, [2].
[6]: Workpaper #2 to Table 2, Panel B.
[7]: Supplementary Exhibit 3, [3].
[8]: Provided by Portland General.
[9]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

Overall After-Tax DCF Cost of Capital of the Electric Sample

Panel C: Multi-Stage DCF (Using average of Blue Chip and OMB Long-Term GDP Growth Forecasts as the Perpetual Rate)

Company	3rd Quarter, 2014 Bond Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	Portland General's Income Tax Rate	Overall After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
ALLETE	BBB	9.5%	0.62	-	0.00	4.5%	0.38	39.9%	6.9%
Alliant Energy	A	8.4%	0.63	4.1%	0.02	4.1%	0.35	39.9%	6.2%
Amer. Elec. Power	BBB	8.8%	0.58	-	0.00	4.5%	0.42	39.9%	6.3%
Ameren Corp.	BBB	9.7%	0.61	-	0.00	4.5%	0.39	39.9%	7.0%
CenterPoint Energy	A	9.6%	0.53	-	0.00	4.1%	0.47	39.9%	6.2%
CMS Energy Corp.	BBB	8.7%	0.49	-	0.00	4.5%	0.51	39.9%	5.6%
Consol. Edison	A	8.6%	0.60	-	0.00	4.1%	0.40	39.9%	6.1%
Dominion Resources	A	8.6%	0.63	4.1%	0.00	4.1%	0.36	39.9%	6.4%
DTE Energy	BBB	8.5%	0.63	-	0.00	4.5%	0.37	39.9%	6.3%
Edison Int'l	BBB	7.3%	0.59	4.5%	0.06	4.5%	0.35	39.9%	5.5%
El Paso Electric	BBB	8.3%	0.59	-	0.00	4.5%	0.41	39.9%	6.0%
Entergy Corp.	BBB	8.3%	0.54	4.5%	0.01	4.5%	0.45	39.9%	5.7%
G't Plains Energy	BBB	8.9%	0.51	4.5%	0.00	4.5%	0.49	39.9%	5.9%
IDACORP Inc.	BBB	7.6%	0.66	-	0.00	4.5%	0.34	39.9%	5.9%
MGE Energy	AA	7.7%	0.78	-	0.00	3.9%	0.22	39.9%	6.6%
OGE Energy	A	8.1%	0.71	-	0.00	4.1%	0.29	39.9%	6.4%
Otter Tail Corp.	BBB	10.0%	0.67	-	0.00	4.5%	0.33	39.9%	7.6%
PG&E Corp.	BBB	9.6%	0.60	4.5%	0.01	4.5%	0.39	39.9%	6.9%
Pinnacle West Capital	A	8.7%	0.66	-	0.00	4.1%	0.34	39.9%	6.6%
Portland General	BBB	8.4%	0.54	-	0.00	4.5%	0.46	39.9%	5.7%
Public Serv. Enterprise	BBB	8.6%	0.69	-	0.00	4.5%	0.31	39.9%	6.7%
SCANA Corp.	BBB	9.0%	0.56	-	0.00	4.5%	0.44	39.9%	6.2%
Sempra Energy	BBB	8.0%	0.67	4.5%	0.00	4.5%	0.33	39.9%	6.3%
Southern Co.	A	9.3%	0.62	4.1%	0.02	4.1%	0.36	39.9%	6.7%
Vectren Corp.	A	9.1%	0.69	-	0.00	4.1%	0.31	39.9%	7.0%
Westar Energy	BBB	8.6%	0.58	-	0.00	4.5%	0.42	39.9%	6.2%
Xcel Energy Inc.	A	8.8%	0.58	-	0.00	4.1%	0.42	39.9%	6.1%
Multi Full Sample Average		8.7%	0.61	4.3%	0.00	4.3%	0.38	39.9%	6.3%

Sources and Notes:

[1]: S&P Rating as of December 9, 2014.
[2]: Exhibit 1101 - B; Panel C, .
[3]: Supplementary Exhibit 3, [1].
[4]: Workpaper #2 to Table 2, Panel C.
[5]: Supplementary Exhibit 3, [2].
[6]: Workpaper #2 to Table 2, Panel B.
[7]: Supplementary Exhibit 3, [3].
[8]: Provided by Portland General.
[9]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

DCF Cost of Equity at Portland General's Representative Capital Structure

Electric Sample

	Overall After -Tax Cost of Capital [1]	Portland General's Representative Regulatory % Debt [2]	Representative Cost of BBB Rated Utility Debt [3]	Portland General's Income Tax Rate [4]	Portland General's Representative Regulatory % Equity [5]	Estimated Return on Equity [6]
Full Sample						
Simple DCF Quarterly	6.9%	50.0%	4.5%	39.9%	50.0%	11.2%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Rate	6.3%	50.0%	4.5%	39.9%	50.0%	9.8%
Multi-Stage DCF - Using the average of the OMB and Blue Chip Economic Indicator Long-Term GDP Growth Forecasts as the Perpetual Rate	6.3%	50.0%	4.5%	39.9%	50.0%	10.0%

Sources and Notes:
[1]: Exhibit 1101 - D; Panels A-C, [9].
[2]: Provided by Portland General.
[3]: Based on a BBB rating. Yield from Bloomberg as of December 9, 2014.
[4]: Provided by Portland General.
[5]: Provided by Portland General.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

Exhibit 1102: Risk Premium Analysis

		Estimated ROE
Regression Analysis	[1]	10.7%
Premium over Allowed ROE	[2]	10.0%
Premium over Earned ROE	[3]	10.6%

Sources and notes:
[1]: WP1 to Table 5
[2]: WP2 to Table 5
[3]: WP3 to Table 5

Portland General Electric

WP1

Risk Premiums Determined by Relationship Between Authorized ROEs and Long-term Treasury Bond Rates[a/]
During the Period 1990-2014 Q3

Formula: Risk Premium = A_0 + (A_1 x Treasury bond Rate)

R Squared	77.6%
Estimate of intercept (A_0)	0.08685
Estimate of slope (A_1)	-0.5731

Equity Cost Estimate for Typical Electric Utility		Predicted Risk Premium		Expected Treasury Bond Rate[b/]
10.7%	=	6.03%	+	4.64%

Sources and Notes:
_a/ Source of ROE Data: SNL Financial
_b/ Average of forecasts for 2016 and 2017 as reported by Blue Chips Economic Indicators
See regression results on Rate Case Data tab

Portland General Electric

WP2

Risk Premium Analysis, 1997 - 2014

	Allowed Return on Equity[a/]	Long-term Treasury Bond Rates[b/]	Average Annual Risk Premiums (over Treasuries)
1997	11.44%	6.63%	4.81%
1998	11.87%	5.64%	6.23%
1999	10.80%	6.36%	4.44%
2000	11.43%	6.09%	5.34%
2001	11.09%	5.65%	5.44%
2002	11.16%	5.37%	5.80%
2003	10.97%	4.87%	6.10%
2004	10.75%	4.99%	5.77%
2005	10.54%	4.62%	5.92%
2006	10.36%	4.98%	5.38%
2007	10.36%	4.88%	5.48%
2008	10.46%	4.15%	6.31%
2009	10.48%	4.21%	6.27%
2010	10.34%	4.02%	6.32%
2011	10.29%	3.41%	6.88%
2012	10.17%	2.55%	7.62%
2013	10.02%	3.26%	6.77%
2014	10.00%	3.17%	6.83%
	Average over period	4.71%	5.98%
	2016 Forecasted Bond Rate		3.80%
	2017 Forecasted Bond Rate		4.20%
	Expected 10 Year Treasury Bond Rate[c/]		4.00%
	10- Year Average Historic Spread of 20 Year Treasuries over 10 Ye		0.64%
	Expected 20 Year Treasury Bond Rate		4.64%
	Projected Returns on Equity for Sample Average over period		10.0%

Notes and Sources:

a/ SNL Financial
b/ Bloomberg Data as of 12.3.2014
c/ Blue Chip Economic Indicators Forecast, average of 2016 and 2017 estimates

Portland General Electric

WP3

Risk Premium Analysis, 1997 - 2014

	Earned Return on Equity[a/]	Long-term Treasury Bond Rates[b/]	Average Annual Risk Premiums (over Treasuries)
1997	10.40%	6.63%	3.77%
1998	10.90%	5.64%	5.26%
1999	12.20%	6.36%	5.85%
2000	7.00%	6.09%	0.91%
2001	12.30%	5.65%	6.65%
2002	9.80%	5.37%	4.44%
2003	10.50%	4.87%	5.63%
2004	11.10%	4.99%	6.12%
2005	11.60%	4.62%	6.98%
2006	11.30%	4.98%	6.32%
2007	12.10%	4.88%	7.22%
2008	11.80%	4.15%	7.65%
2009	10.60%	4.21%	6.39%
2010	11.00%	4.02%	6.98%
2011	10.80%	3.41%	7.39%
2012	8.08%	2.55%	5.52%
2013	9.54%	3.26%	6.28%
2014	10.62%	3.17%	7.45%
	Average over period	4.71%	5.93%
	2016 Forecasted Bond Rate		3.80%
	2017 Forecasted Bond Rate		4.20%
	Expected 10 Year Treasury Bond Rate[c/]		4.00%
	10- Year Average Historic Spread of 20 Year Treasuries over 10 Ye		0.64%
	Expected 20 Year Treasury Bond Rate		4.64%
	Projected Returns on Equity for Sample Average over period		10.6%

Notes and Sources:

a/ Zepp UE 283 Testimony
b/ Bloomberg Data as of 12.3.2014
c/ Blue Chip Economic Indicators Forecast, average of 2016 and 2017 estimates

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:

$$r_S = r_f + \beta_S \times MRP \qquad (1)$$

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. When determining 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 2016 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 2016 as a reasonable representative 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 2016, I obtain a risk-free rate estimate of 4.03%.

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 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.[1] 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 1 from Duarte & Rosa 2014 is replicated in PGE Exhibit 1106, which shows the average estimated MRP (over 30-day T-bills) for 20 models.[2] 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-

[1] Fernando Duarte and Carlo Rosa, "The Equity Risk Premium: A Consensus of Models," Federal Reserve Bank of New York, 2014 (Duarte & Rosa 2014).
[2] 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.

term MRP of 10.2% over 20-year government bonds. Similarly, Bloomberg's forecasted MRP is higher than the historical average at approximately 7.74% over 10-year Treasury bonds.[3] At the same time Morningstar / Ibbotson's historical measure for the period 1926 – 2013 was 6.96%.[4] For the purpose of this proceeding I rely on the historical estimate of 6.96%.[5]

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 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.[6] 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

[3] Bloomberg as of 1/8/2015. As Bloomberg estimates the MRP over 10-year Treasury bonds, the equivalent figure over 20-year bonds is approximately 7.1% as the historical spread between 10-year and 20-year government bonds is approximately 0.64% from 2000 through today. See Exhibit 1106.
[4] Duff & Phelps, *2014 Valuation Handbook*, Exhibit 3-6.
[5] I have in the past used a range of MRP estimates, but given the Commission has not relied on the CAPM in recent years, I use only the historical MRP in this proceeding.
[6] See Brealey, Myers and Allen (2011), *Principles of Corporate Finance*, 10th Edition, McGraw-Hill Irwin, New York, p. 166.

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.

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 .60 to .95 with Portland General at .80 being above the average of about .75.

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,

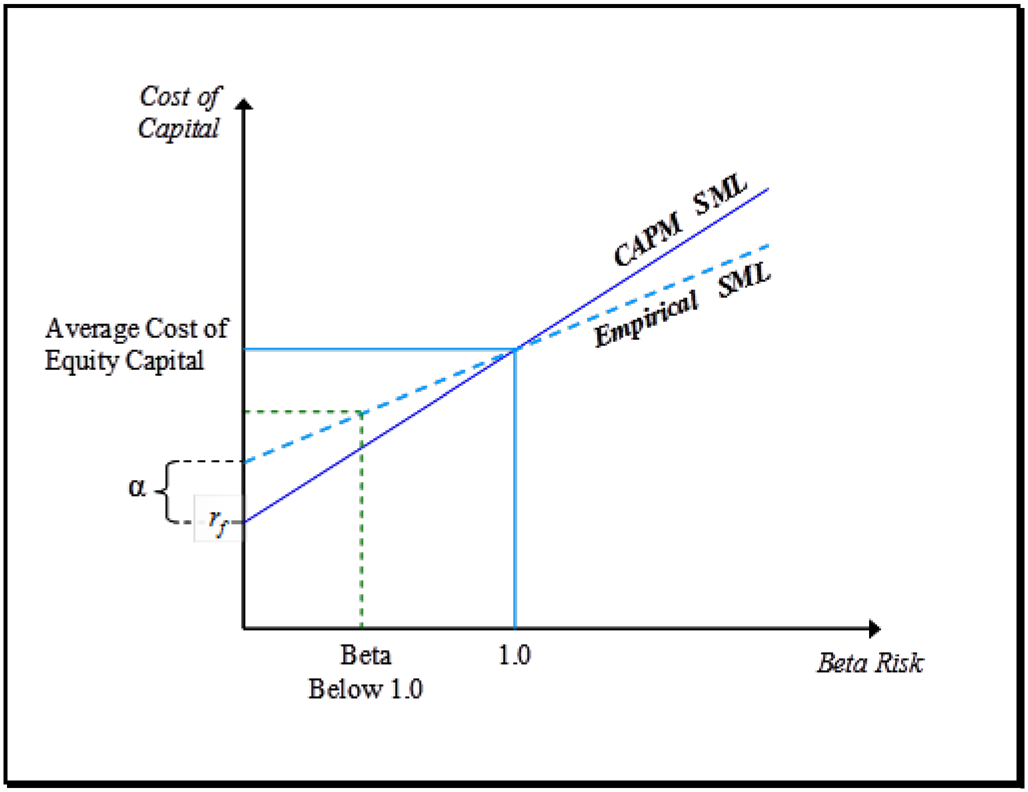
$$r_S = r_f + \alpha + \beta_S \times \left(MRP - \alpha\right) \qquad (2)$$

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



Q. Can you summarize the results from applying the CAPM and ECAPM methodologies to the sample?

A. The results of the risk positioning analyses (the CAPM and the ECAPM) are presented below in Table 3-1. For the ECAPM, there are two sensitivities: α = 0.5% and α = 1.5%. As was the case for the DCF results presented in Table 3 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

	Estimated ROE
CAPM	9.8%
ECAPM (α = 0.5%)	10.0%
ECAPM (α = 1.5%)	10.2%

Q. What conclusions do you draw from the CAPM / ECAPM results?

A. The CAPM / ECAPM cost of equity estimates are broadly consistent with those obtained using the DCF and risk premium models as well as with the currently allowed ROE for electric utilities.

Electric Sample

CAPM using Value Line Betas

	Overall After-Tax Cost of Capital [1]	Portland General's Representative Regulatory % Debt [2]	Representative Cost of BBB-Rated Utility Debt [3]	Portland General's Income Tax Rate [4]	Portland General's Representative Regulatory % Equity [5]	Estimated Return on Equity [6]
Full Sample:						
CAPM using Value Line Betas	6.3%	50.0%	4.5%	39.9%	50.0%	9.8%
ECAPM (0.50%) using Value Line Betas	6.3%	50.0%	4.5%	39.9%	50.0%	10.0%
ECAPM (1.50%) using Value Line Betas	6.5%	50.0%	4.5%	39.9%	50.0%	10.2%

Sources and Notes:

[1]: Schedule D6.11; Panel A, [10] - [12].

[2]: Provided by Portland General.

[3]: Based on a BBB rating. Yield from Bloomberg as of December 9, 2014.

[4]: Provided by Portland General.

[5]: Provided by Portland General.

[6]: {[1] - ([2] x [3] x (1 - [4])}/ [5]

Risk Positioning Cost of Equity of the Electric Sample

Using Value Line Betas

Long-Term Risk Free Rate of 4.03%, Long-Term Market Risk Premium of 6.96%

Company	Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (0.5%) Cost of Equity [5]	ECAPM (1.5%) Cost of Equity [6]
ALLETE	4.03%	0.80	6.96%	9.6%	9.7%	9.9%
Alliant Energy	4.03%	0.80	6.96%	9.6%	9.7%	9.9%
Amer. Elec. Power	4.03%	0.70	6.96%	8.9%	9.1%	9.4%
Ameren Corp.	4.03%	0.75	6.96%	9.3%	9.4%	9.6%
CenterPoint Energy	4.03%	0.75	6.96%	9.3%	9.4%	9.6%
CMS Energy Corp.	4.03%	0.75	6.96%	9.3%	9.4%	9.6%
Consol. Edison	4.03%	0.60	6.96%	8.2%	8.4%	8.8%
Dominion Resources	4.03%	0.70	6.96%	8.9%	9.1%	9.4%
DTE Energy	4.03%	0.75	6.96%	9.3%	9.4%	9.6%
Edison Int'l	4.03%	0.75	6.96%	9.3%	9.4%	9.6%
El Paso Electric	4.03%	0.70	6.96%	8.9%	9.1%	9.4%
Entergy Corp.	4.03%	0.70	6.96%	8.9%	9.1%	9.4%
G't Plains Energy	4.03%	0.85	6.96%	9.9%	10.0%	10.2%
IDACORP Inc.	4.03%	0.80	6.96%	9.6%	9.7%	9.9%
MGE Energy	4.03%	0.70	6.96%	8.9%	9.1%	9.4%
OGE Energy	4.03%	0.85	6.96%	9.9%	10.0%	10.2%
Otter Tail Corp.	4.03%	0.95	6.96%	10.6%	10.7%	10.7%
PG&E Corp.	4.03%	0.65	6.96%	8.6%	8.7%	9.1%
Pinnacle West Capital	4.03%	0.70	6.96%	8.9%	9.1%	9.4%
Portland General	4.03%	0.80	6.96%	9.6%	9.7%	9.9%
Public Serv. Enterprise	4.03%	0.75	6.96%	9.3%	9.4%	9.6%
SCANA Corp.	4.03%	0.75	6.96%	9.3%	9.4%	9.6%
Sempra Energy	4.03%	0.75	6.96%	9.3%	9.4%	9.6%
Southern Co.	4.03%	0.60	6.96%	8.2%	8.4%	8.8%
Vectren Corp.	4.03%	0.80	6.96%	9.6%	9.7%	9.9%
Westar Energy	4.03%	0.75	6.96%	9.3%	9.4%	9.6%
Xcel Energy Inc.	4.03%	0.70	6.96%	8.9%	9.1%	9.4%

Sources and Notes:
[1]: Villadsen direct testimony.
[2]: From Valueline Investment Analyzer as of Dec 09, 2014.
[3]: Villadsen direct testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 0.5%) + [2] x ([3] - 0.5%).
[6]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Past Rate Cases

			Increase Authorized	
State	Company	Date	ROE (%)	Common Equity /Total Cap (%)
Arkansas	Entergy Arkansas Inc.	12/30/2013	9.30	28.64
California	Pacific Gas and Electric Company	8/14/2014	NA	NA
Connecticut	United Illuminating Co.	8/14/2013	9.15	50.00
Delaware	Delmarva Power & Light Co.	4/2/2014	9.70	49.22
District of Columbia	Potomac Electric Power Co.	3/26/2014	9.40	49.19
District of Columbia	Potomac Electric Power Company	11/12/2014	NA	NA
Florida	Gulf Power Co.	12/3/2013	10.25	NA
Florida	Tampa Electric Co.	9/11/2013	10.25	42.00
Florida	Florida Public Utilities Company	9/15/2014	10.25	NA
Georgia	Georgia Power Co.	12/23/2013	NA	NA
Georgia	Georgia Power Co.	12/17/2013	10.95	50.84
Idaho	PacifiCorp	10/24/2013	NA	NA
Idaho	Avista Corporation	9/18/2014	NA	NA
Illinois	Ameren Illinois	12/9/2013	8.72	51.00
Illinois	Commonwealth Edison Co.	12/18/2013	8.72	45.28
Illinois	MidAmerican Energy Company	11/6/2014	9.56	51.73
Iowa	MidAmerican Energy Co.	2/28/2014	NA	NA
Kansas	Westar Energy Inc.	11/21/2013	10.00	52.63
Kansas	Kansas City Power & Light Company	7/17/2014	NA	NA
Kentucky	Kentucky Power Co.	11/22/2013	NA	NA
Louisiana	Entergy Gulf States LA LLC	12/16/2013	9.95	NA
Louisiana	Entergy Louisiana LLC	12/16/2013	9.95	NA
Louisiana	Entergy Louisiana, LLC	7/10/2014	9.95	NA
Maine	Emera Maine	6/30/2014	9.55	49.00
Maine	Central Maine Power Company	7/29/2014	9.45	50.00
Maryland	Baltimore Gas and Electric Co.	12/13/2013	9.75	51.05
Maryland	Delmarva Power & Light Co.	9/3/2013	NA	NA
Maryland	Potomac Electric Power Company	7/2/2014	9.62	49.18
Massachusetts	Fitchburg Gas & Electric Light	5/30/2014	9.70	47.78
Michigan	Upper Peninsula Power Co.	12/19/2013	10.15	NA
Mississippi	Mississippi Power Co.	3/5/2013	9.70	NA
Montana	NorthWestern Corporation	9/25/2014	9.80	48.00
Nevada	Sierra Pacific Power Co.	12/16/2013	10.12	46.94
Nevada	Nevada Power Company	10/9/2014	9.80	48.17
New Hampshire	Liberty Utilities Granite St	3/17/2014	9.55	55.00
New Jersey	Rockland Electric Company	7/23/2014	9.75	50.35
New Jersey	Atlantic City Electric Company	8/20/2014	9.75	49.83
New York	Consolidated Edison Co. of NY	2/20/2014	9.20	48.00
North Carolina	Duke Energy Carolinas LLC	9/24/2013	10.20	53.00
Oregon	PacifiCorp	12/18/2013	9.80	52.10
Oregon	Portland General Electric Co.	12/9/2013	9.75	50.00
Pennsylvania	Duquesne Light Co.	4/23/2014	NA	NA
South Carolina	Duke Energy Carolinas LLC	9/11/2013	10.20	53.00
South Carolina	South Carolina Electric & Gas	9/18/2013	NA	53.86

South Carolina	South Carolina Electric & Gas Co.	9/24/2014	NA	53.52
Texas	Entergy Texas Inc.	5/16/2014	9.80	NA
Utah	PacifiCorp	8/29/2014	9.80	51.43
Vermont	Green Mountain Power Corporation	8/25/2014	9.60	50.00
Virginia	Appalachian Power Co.	12/17/2013	11.40	44.28
Virginia	Appalachian Power Co.	11/25/2013	NA	NA
Virginia	Kentucky Utilities Co.	11/25/2013	NA	NA
Virginia	Virginia Electric & Power Co.	3/14/2014	11.00	50.00
Virginia	Virginia Electric & Power Co.	3/14/2014	12.00	50.00
Virginia	Virginia Electric & Power Co.	2/28/2014	11.00	50.00
Virginia	Virginia Electric & Power Co.	11/26/2013	10.00	NA
Virginia	Virginia Electric and Power Company	7/8/2014	11.00	50.00
Washington	PacifiCorp	12/4/2013	9.50	49.10
Washington	Puget Sound Energy Inc.	6/25/2013	9.80	48.00
Wisconsin	Madison Gas and Electric Co.	7/26/2013	NA	NA
Wisconsin	Northern States Power Co - WI	12/5/2013	10.20	52.54
Wisconsin	Wisconsin Power and Light Co	6/6/2014	10.40	50.46
Wisconsin	Wisconsin Public Service Corp.	11/6/2013	10.20	50.14
Wisconsin	Wisconsin Public Service Corporation	11/6/2014	10.20	NA
Wisconsin	Wisconsin Electric Power Company	11/14/2014	10.20	NA
Wyoming	Cheyenne Light, Fuel and Power Com	7/31/2014	9.90	54.00
Average authorized ROE (all)			9.96	
Average authorized ROE (selected)			9.96	

Source: SNL, RRA Rate Case Decisions, as of January 7, 2015

Note: Cases shaded in gray are excluded because they are generation incentive or distribution only ROEs

Capital structure for major rate case decisions 2000 - September 2014

Year	Period	% Equity	% Debt
2000	Full Year	48.85	51.15
2001	Full Year	47.20	52.80
2002	Full Year	46.27	53.73
2003	Full Year	49.41	50.59
2004	Full Year	46.84	53.16
2005	Full Year	46.73	53.27
2006	Full Year	48.67	51.33
2007	Full Year	48.01	51.99
2008	Full Year	48.41	51.59
2009	Full Year	48.61	51.39
2010	Full Year	48.45	51.55
2011	Full Year	48.26	51.74
2012	Full Year	50.55	49.45
2013	Full Year	49.25	50.75
2014	Year-To-Date	50.52	49.48
Average		48.40	51.60

Source: Regulatory Research Associates, "Major Rate Case Decisions - January - September 2014," October 10, 2014, p. 4.

PGE Exhibit 1106

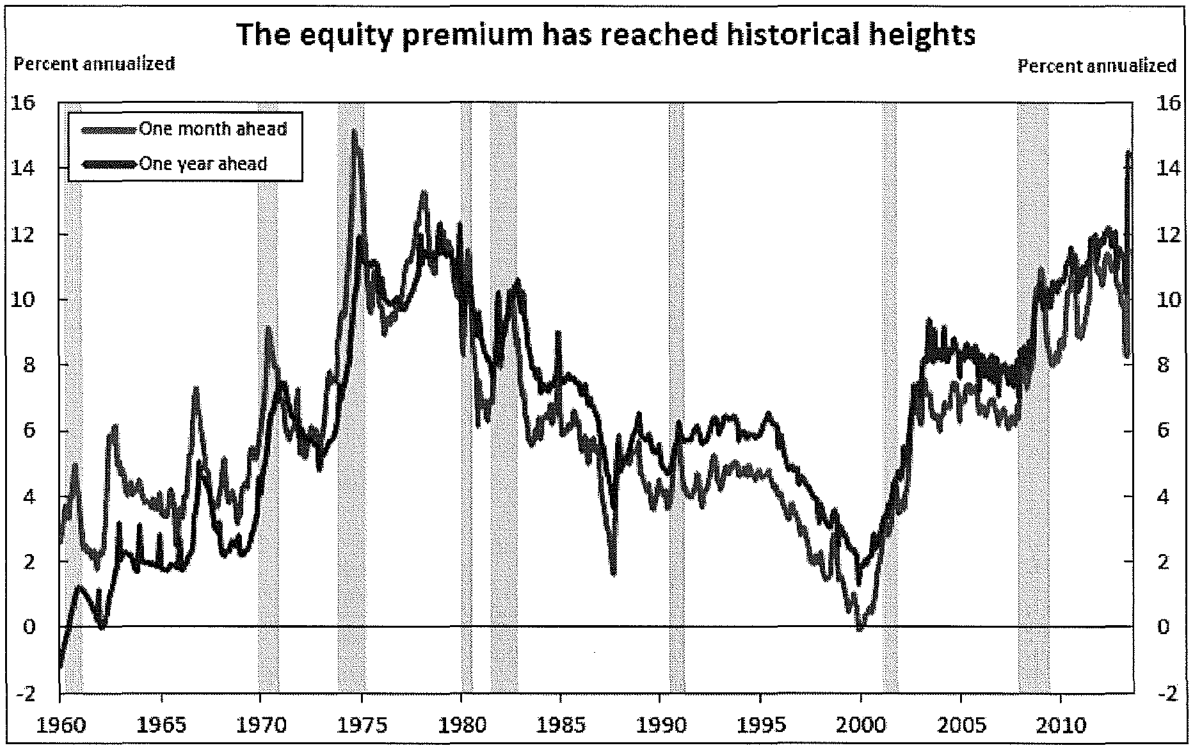


Figure 1 The equity risk premium (expected excess returns) over a one year ahead and one month ahead horizons are the first principal components of 20 models of the equity premium. The models include time-series and cross-sectional regressions, dividend discount models and surveys. Shaded bars are NBER recessions.

Source: Fernando Duarte and Carlo Rosa, "The Equity Risk Premium: A Consensus of Models," Federal Reserve Bank of New York, 2014, Figure 1.

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Country Risk Premium: History

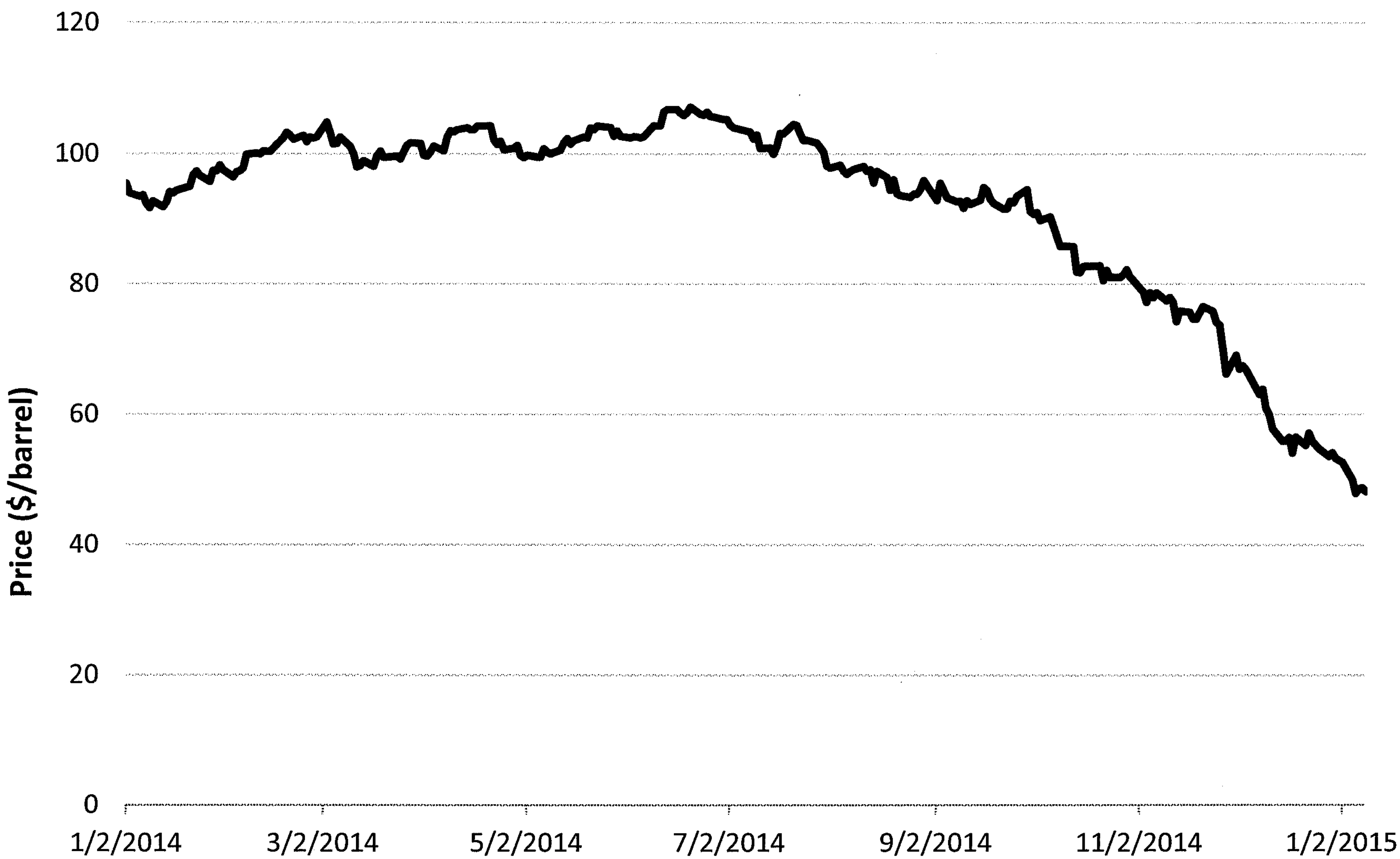
01/09/05 - 01/09/15 Daily RFR USGG10YR Index Curr USD United States

Date	Div Yld	Grwth Rate	Div Pay Ratio	Mkt Return	RF Rate	Premium
01/08/15	2.010%	11.372%	35.537%	9.759%	2.018%	7.741%
01/07/15	2.043%	11.372%	35.513%	9.836%	1.968%	7.868%
01/06/15	2.071%	11.353%	35.382%	9.876%	1.940%	7.936%
01/05/15	2.054%	11.403%	35.300%	9.859%	2.032%	7.827%
01/02/15	2.035%	11.467%	35.406%	9.777%	2.111%	7.667%
12/31/14	2.005%	11.490%	33.556%	9.240%	2.171%	7.069%
12/30/14	1.984%	11.477%	33.596%	9.199%	2.187%	7.012%
12/29/14	1.975%	11.473%	33.601%	9.179%	2.202%	6.977%
12/26/14	1.976%	11.554%	33.595%	9.236%	2.250%	6.986%
12/24/14	1.983%	11.704%	33.596%	9.292%	2.263%	7.029%
12/23/14	1.982%	11.700%	33.600%	9.292%	2.261%	7.031%
12/22/14	1.986%	11.716%	33.599%	9.309%	2.158%	7.151%
12/19/14	1.994%	11.733%	33.587%	9.349%	2.162%	7.187%
12/18/14	2.002%	11.717%	33.575%	9.376%	2.208%	7.169%
12/17/14	2.050%	11.729%	33.565%	9.504%	2.136%	7.368%
12/16/14	2.089%	11.686%	33.557%	9.584%	2.059%	7.525%
12/15/14	2.066%	11.723%	33.546%	9.555%	2.118%	7.437%
12/12/14	2.047%	11.727%	33.554%	9.523%	2.082%	7.441%
12/11/14	2.011%	11.698%	33.549%	9.459%	2.162%	7.297%

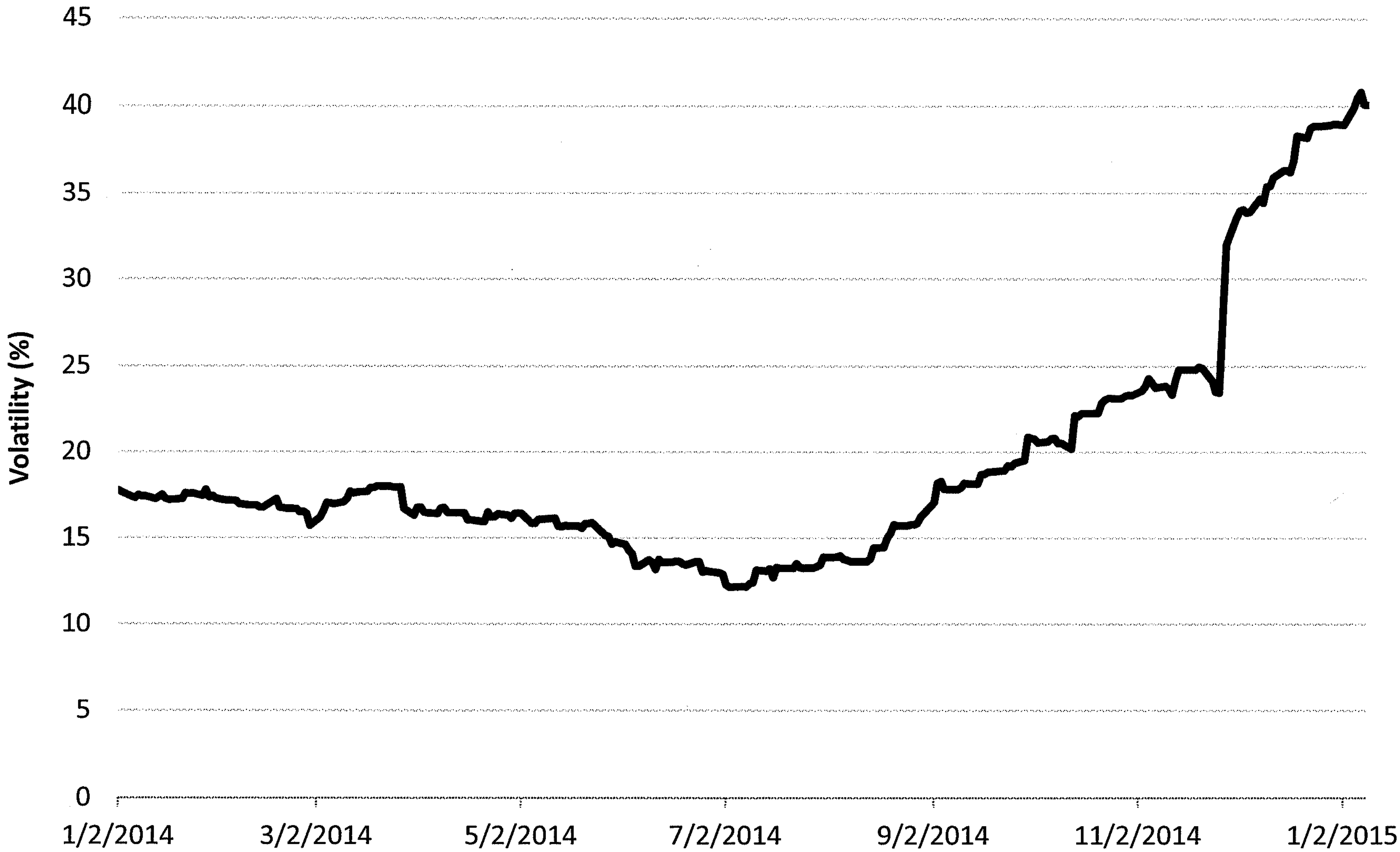
Chart Chart Options

300) Edit Panel 301) Expand Panel

338 WAU 17:01 Essendon veteran Dustin Fletcher relishes prospect of another pre-
337 WAU 17:01 Essendon, Port Adelaide to keep talking on Paddy Ryder
336 WPT 17:01 What Would Happen If the Supreme Court Dismembers Obamacare



Source: Bloomberg as of 1/9/2015; Follows price of West Texas Intermediate (WTI) crude oil



Source: Bloomberg as of 1/9/2015; Follows price of WTI crude oil; The 60-day price volatility equals the annualized standard deviation of the relative price change for the 60 most recent trading days closing price, expressed as a percentage.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Sarah Dammen
Amber Riter

February 12, 2015

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 employed by PGE as the Lead Load Forecast Analyst.

My name is Amber M. Riter. I am employed by PGE as a Forecasting Analyst. 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 explains the development of PGE's 2016 test year energy and customer forecast.

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 as described below, 2) set a schedule in this proceeding similar to prior proceedings allowing for periodic updates of the energy delivery forecast for 2016, and 3) consider possible modeling updates to reflect recommended changes to the customer forecast as further described below.

Q. Please describe PGE's delivery forecast.

A. PGE's 2016 test year energy forecast is for energy deliveries of 19,562 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 2016, as well as operational changes among PGE's largest customers and takes into account the effect on energy consumption of anticipated higher electricity prices in 2016 (compared to November

2014 base period prices) 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 2016 forecast compare to recent historical demand?

A. Similar to the energy delivery trends of recent years, the 2016, forecast reflects strong growth in deliveries to industrial (primary service) customers related to high-tech expansion and modest or no growth in the residential and commercial sectors. The underlying growth in industrial energy deliveries is masked in 2016 by a significant operational change at a large paper manufacturing customer who expects to supply increased onsite generation beginning in 2016. This customer is on transmission voltage service.

Table 1 below summarizes the MWh delivery forecast in annual percentage changes by voltage service customer class on a billing cycle basis from 2012 through 2016.

Table 1

Percent Change in MWh Delivery from Preceding Year: 2012-2016

Voltage Service Class	2012	2013	2014	2015 (E)	2016 (E)
Residential	0.4%	0.1%	0.1%	0.1%	0.0%
Secondary	0.1%	-0.3%	1.7%	0.4%	0.2%
Transmission	-2.1%	-2.7%	-21.9%	-1.4%	-34.3%
Primary	3.1%	1.9%	8.3%	6.7%	4.9%
Street Lighting	0.2%	-1.7%	-9.8%	-11.0%	-10.9%
Total	0.6%	0.1%	0.8%	1.3%	-0.5%

Q. Does PGE adjust the base forecast for price elasticity effects?

A. Yes. PGE expects customers to respond to price increases by making behavioral changes to decrease usage in the short-term, and over time making changes to the capital stock including purchasing more energy efficient appliances and equipment.

Q. What price change assumptions did you make to calculate the price effect on demand?

A. Based on the information known at the time of the load forecast, we assumed a nominal price change of 2.7% in January 2016, followed by a 3.9% price increase in May 2016 for residential customers and a 2.3% price change in January 2016 followed by a 4.9% nominal price change in May 2016 for non-residential customers. In January 2015, we assumed a nominal price change of 0.9% above November 2014 levels for residential customers and 1.1% above November 2014 for non-residential customers.

Q. What price change assumptions will be used to update the calculated price effect on demand during this proceeding?

A. Load forecast updates during this case will use 2016 price change estimates that account for stipulations, changes in Net Variable Power Costs (NVPC) and other relevant information known at that time. The 2015 price changes are based on the final commission order in UE 283 General Rate Case.

Q. What price elasticity does PGE estimate and use in the forecast?

A. We used elasticity estimates of -0.1 for residential demand and -0.03 for nonresidential demand. A price elasticity of -0.1 means that if electricity prices rose an average of 10%, MWh demand would decline by 1%, all else equal. As we pointed out in previous general rate cases,[1] these elasticity estimates are relatively small, have remained stable since 2002 and are consistent with price elasticities estimated for the Northwest. Using these estimates of elasticity and the assumed price increases, the price-effect (P) forecast is about 48 thousand MWh or 0.2% lower than the base (B) forecast for 2016. The base (B) forecast is

[1] UE 180, UE 197, UE 215, UE 262, and UE 283

provided in PGE Exhibit 1201 and the price-effect (P) forecast is provided in PGE Exhibit 1202.

Q. Did you make any adjustments beyond the impact of electricity price changes to the delivery 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 2014. EE trends, including Senate Bill 1149 (SB1149)[2] measures are assumed to be captured implicitly in the forecast model; therefore no explicit adjustments are made for SB1149 energy efficiency savings. The assumed incremental EE program levels incorporate new funding for EE programs beyond prior levels, starting in December 2014 the first month of the forecast. ETO developed the estimates of these "incremental savings" for PGE based on measures achievable at a levelized cost up to 10.0 cents per kWh for a cost-effectiveness upper limit, or an average levelized cost of 4.2 cents per kWh. 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 average quarterly achieved savings over 2011, 2012 and 2013.

Q. How significant is the impact of incremental EE programs savings on PGE's delivery forecast?

A. We estimate a total of 264.5 thousand MWh or 1.3% savings from these programs in the 2016 test year based on the EE savings starting in December 2014 and accumulating through

[2] Among other things, Oregon Senate Bill 1149 established the 3% public purpose charge to fund and encourage energy conservation.

December 2016. PGE Exhibit 1203 shows the forecast adjusted for incremental EE savings and PGE Exhibit 1204 shows the savings from the incremental EE programs that are included in PGE's delivery forecast.

II. Model and Forecast Process

Q. Please summarize the process you use to develop the retail energy delivery forecast.

A. The core energy delivery (load) models and the forecast process are the same as those used in previous rate cases and regulatory filings. Regression models are estimated for residential, commercial and manufacturing sectors using data from an extended historical period through October 2014. Energy delivery models are estimated based on the historic relationship between energy deliveries and economic variables, weather variables and seasonal control variables. The most current, available forecasts of the economic drivers are then used with the coefficients from the regression models to develop the energy delivery forecast.

Q. Are these models new or different from previous PGE load models?

A. No. The forecast models and process remains fundamentally the same as that used in previous filings with the Commission. Past testimonies on the PGE load forecast describe in detail the theory and structure of our model, as well as our forecast processes. These were submitted in various regulatory proceedings, most recently in the November Power Cost update filing for UE 266 (Load Forecast Work Papers), UE 262 General Rate Case (PGE Exhibit 1300) and UE 283 General Rate Case (PGE Exhibit 200).

Q. Please summarize the recent third-party review of PGE's short-term load forecast methodology and process.

A. In October 2014, PGE engaged Itron to perform a third-party review of PGE's models and forecast process to assess how PGE's load forecasting process and models compare to industry best practices. The evaluation consisted of reviewing various aspects of PGE's load forecast model including the short-term energy and customer models. Itron found that PGE's short-term energy methods are consistent with standard industry practice and its model results akin to industry benchmark growth rates. The review found that PGE is in the minority of industry practice with respect to customer forecast method, which we currently base on forecasting connects and using a cohort survival method to calculate customers.[3] As we discuss below, we intend to explore a change in the customer forecast methodology.

Q. Were there other findings relevant to the 2016 test-year forecast?

A. Yes. Itron found that PGE's price elasticities were consistent with industry benchmark price elasticities and that PGE's adjustment for energy efficiency is consistent with common practice in the industry.

Q. What are the recommendations for refinements to the short-term energy models from the third-party review?

A. Itron recommended refinements to the short-term energy models focus on economic and weather variable selection in the regression models and changes that reduce the complexity of the models.

- With respect to modeling of weather, Itron recommended using multi-part splines with lower heating degree day (HDD) breakpoints for most of the models.
- For some models, alternative economic drivers and/or shortened estimation periods were recommended to capture the changing relationship between energy deliveries and economic drivers.

[3] A cohort survival method uses prior period customer count and applies a survival rate to account for customer attrition (e.g., demolitions or inactive accounts) and then adds forecasted customer new connects to forecast the total customer count. Customer attrition is based on a statistical model of customer survival from one billing period to the next, where on average roughly 99.94% of customers are still active month-to-month.

- Removing the polynomial distributed lag (PDL) structures from the models in favor of lagged dependent variables is a third recommendation that primarily simplifies the models and improves the interpretability of the model results.

The above recommendations are all intended to reduce complexity in the models and increase interpretability. The recommendations are not intended to alter the trajectory or magnitude of the forecast, particularly in the short-term.

Q. Did PGE make any changes as a result of the third party review?

A. Yes, PGE made refinements to the short term energy models used to develop the forecast for this filing as a result of the third-party review.

Q. Please describe the refinements implemented in the forecast presented in this proceeding based on the third-party review.

A. Recommended refinements to the energy models have been made with respect to the use of lower HDD breakpoints and multi-part weather splines; and the forecast drivers and estimation periods have been extensively analyzed to capture changing relationships between energy consumption and the sector drivers. Most models are now based on shorter estimation periods determined by changes in the trajectory of energy consumption or the change in relationship with respect to the economic drivers.

Q. Does PGE intend to update its 2016 forecast during this case?

A. Yes, we intend to update the test-year delivery forecast as we have in prior cases using the most current input assumptions and to re-estimate the models. Updates include incorporation of additional actual load and economic data as they become available, as well as updating for changes in forward looking inputs including revisions to the economic outlook for the U.S. and Oregon, any changes to large customers' usage forecasts and other components such as demand elasticity and price changes. Our forecast updates typically occur each quarter, following the release of the Oregon Office of Economic Analysis (OEA) quarterly forecast, though PGE does not intend to update the forecast in March unless there are significant changes in the forecast drivers and information from those used in this initial filing.

Q. Does PGE intend to implement additional third-party recommendations to the forecast models or forecast process during this case?

A. Yes. PGE intends to develop, test and likely implement recommendations related to PGE's long-term energy approach and peak models during this case in support of PGE's 2016 Integrated Resource Plan (IRP) resource requirement modeling. The changes would be focused on the long-term and peak forecast, not the 2016 test-year energy forecast. PGE intends to hold load forecast workshops in the 2016 IRP proceeding to review the methodology update process and present changes to the long-term and peak models to stakeholders.

Q. Does PGE intend to implement any additional third-party recommendations to the forecast models or forecast process during this case that would impact the 2016 test year energy forecast?

A. Time permitting, PGE would like to explore implementation of the customer forecast recommendation; however, PGE would not implement a change to the customer forecast approach unless parties were in agreement.

Q. Please describe the customer forecast recommendation.

A. The customer forecast recommendation is to forecast total customer counts (instead of new connects in a survival-type framework) and to use a third-party building permit or population forecast as the primary driver. The intent of this change is to simplify the customer count forecasting process and strengthen the statistical relationship between customer forecast and population or building permits forecasts. PGE would not propose any change that materially impacted the customer count forecast during this case, nor would PGE expect the change in methodology to materially change the customer forecast.

Q. What sources of information do you use to forecast electricity delivery?

A. As in past forecasts, PGE relies on two sources of economic information to drive our forecast: 1) a national economic forecast, and 2) the Oregon state economic and unemployment forecasts. IHS Global Insight provides the US economic forecast. The Oregon Department of Administrative Services (OEA) provides the Oregon economic forecast (Oregon Economic and Revenue Forecast) including the state unemployment forecast. Global Insight's November 2014 forecast and OEA's December 2014 forecast were used to develop the MWh delivery forecast for this proceeding. These were the most current forecasts available at the time of the development of the forecast. In addition, customers who are large energy users provide us with specific operational information, direct inputs and, if available, forecast 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. We used the 15-year average weather observed from 1999 through 2013. Since UE 180, we have been using 15-year moving averages to represent forward looking normal weather conditions.

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 2014 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.

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. 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, transportation equipment, and shipyards, among others, that serve national and global markets.

In our model, we group commercial and manufacturing customers according to the North America Industrial Classification System (NAICS) definition of business segments. MWh projections for the three end-use sectors are developed separately and then summed together with the forecast of miscellaneous schedules (streetlight, irrigation, etc.) to obtain total end-use energy.

Finally, allocation factors based on the most recent year are used to allocate the NAICS segment delivery forecasts into voltage-level (rate schedule) MWh deliveries using their respective preceding-year ratios.

Q. How do you forecast the ultimate loads delivered to the PGE distribution system?

A. This process involves three steps: 1) aggregated cycle-based NAICS sector MWh deliveries are converted into various voltage service levels, 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 the MWh deliveries at the meter to obtain the bus bar average megawatt (MW) and MW demand (peak) required to meet the end users' demand. For test year 2016, we apply updated line loss factors beginning in 2015 as established in UE 283. We use monthly voltage-level and system load factors to calculate the monthly peak MW based on the projected average MW. PGE Exhibit 1210 displays the forecast of total distribution loads in annual average MW and MW peak demand.

III. Forecast Results

Q. What are the key results of PGE's residential sector forecast?

A. For the test year 2016, we forecast deliveries of 7,625 thousand MWh to 748,413 residential customers. The assumed price increase and the incremental EE programs combine to offset any customer-driven increase in deliveries in 2016 relative to forecasted 2015. The forecasted 2016 residential energy deliveries are comparable to 2015 (0.0% change). In comparison, residential energy deliveries increased 0.1%, on a weather-adjusted basis, in 2013 and 2014 and deliveries are forecasted with a 0.1% increase in 2015. The residential forecast includes residential outdoor area lighting energy.

The energy forecast reflects an increase of 0.9% in the number of residential customers in 2015, and 0.9% in 2016, compared to a 1.0% increase in 2014 and a 0.7% increase in 2013. PGE Exhibit 1205 shows the forecast of building permits, new connects, and customer counts. PGE Exhibit 1206 displays the forecast of kWh use per occupied account and deliveries to residential customers in detail.

Q. What are the key results of PGE's commercial sector forecast?

A. For test year 2016, we forecast deliveries of 7,039 thousand MWh to NAICS-based commercial customers, a 0.2% increase over forecasted 2015 energy deliveries of 7,026 thousand MWh. As with residential customers, we expect rising electricity prices to have an impact on MWh delivery to commercial customers, albeit to a lesser degree due to this sector's inelastic demand response (i.e., relatively small nonresidential price elasticity). On the other hand, the savings from incremental EE programs in the commercial sector are larger than those in the residential sector. Energy deliveries to this market segment, adjusted for weather, increased 0.2% in 2012, decreased 0.5% in 2013 and increased 1.2% in 2014.

We forecast energy delivery to this market segment, after accounting for price impacts and EE program savings, to increase 0.5% in 2015 and to increase 0.2% in 2016. The growth of 1.2% in 2014 and forecasted growth for 2015 reflects the return of some growth after the decline in actual weather-adjusted delivery in 2013, while the 2016 forecasted increase is smaller due to the reduction in demand due to the accumulation of EE savings as well as the price adjustments.

PGE Exhibit 1207 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 2016, we forecast deliveries of 4,724 thousand MWh. Test year deliveries to manufacturing customers are projected to be 2.2% lower than the forecasted 2015 deliveries, which are forecasted at 4.6% higher than 2014 weather-adjusted deliveries. Manufacturing energy deliveries grew 1.0% in 2013 and 1.7% in 2014 on a weather-adjusted basis. The manufacturing forecast reflects planned expansions by high-tech and related companies in our service territory (on primary voltage service) but also reflects a significant reduction in deliveries to a large customer on transmission voltage service in 2016. Manufacturing sector deliveries can show large swings from year to year due to specific individual company operations and industry conditions. We expect only minimal response to electricity price changes due to the industrial sector's inelastic response and a slightly larger impact from incremental EE programs. PGE Exhibit 1208 presents the detailed delivery forecast of the manufacturing sector.

Q. Describe PGE's manufacturing sector forecast and the challenge in forecasting its energy delivery.

A. PGE's manufacturing sector is concentrated in a few energy-intensive industries and large customers. In 2014, high tech industry accounted for over 46% of all manufacturing sector energy deliveries, the paper industry at roughly 15%, other manufacturing at 16% and metals at 11%. As a result, when one or several of these large manufacturing customers decide to add capacity or to shut down operations in response to company-specific, economic or market conditions or make other operational changes, they have a significant impact on our energy delivery forecast.

Q. What are the key results of PGE's miscellaneous rate schedules forecast?

A. Deliveries under miscellaneous schedules account for approximately 1% of total delivery to all retail customers in 2016. PGE Exhibit 1209 shows the forecast of deliveries under these miscellaneous schedules.

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 2014 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 2016. 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 1211 shows the forecast of deliveries in 2016 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 or exceeds the forecast. As with any forecast, actual conditions may differ from what we assumed or anticipated in the forecast, resulting in a different outcome.

The accuracy of a forecast depends not only on the 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. Our forecast depends on the stability of our model and the accuracy of these input assumptions.

The other major areas of uncertainty involve inputs and assumptions surrounding retail electricity prices, 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. The November 2014 Global Insight and December 2014 OEA baseline economic forecasts were used as key drivers in this forecast. 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 going forward as these organizations develop newer forecasts.

Q. Do changing economic conditions have an effect on PGE's forecast?

A. Yes. Changing economic conditions could result in activities or outcomes that differ from the economic forecast used to drive PGE's delivery forecast and are a key source of uncertainty. Economic forecasts are key drivers of PGE's forecast of MWh delivery, specifically the economic drivers forecasted by Global Insight and the OEA. All else equal, different economic outcomes result in delivery outcomes that differ from the initial forecast. In addition to changing economic conditions is the changing relationship between economic conditions and energy deliveries.

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 filed for bankruptcy, liquidated business, changed ownership or permanently shut down operations, which have substantially affected PGE's actual and anticipated MWh delivery. Specifically, in 2013 and 2014 industrial deliveries were affected by the partial or full closure of paper manufacturers and decline in deliveries to solar manufacturing customers. With respect to announced new developments, we specifically include in this forecast planned expansions and operational changes by high-tech and paper 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 it 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. PGE estimates that one degree variation in temperature could affect (total retail) MWh usage by as much as 1.4% in peak months and as much as 0.5% 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 10 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 a transportation economist for the U.S. Department of Transportation at the Volpe Transportation Systems Center in Cambridge, MA.

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. My graduate work specialization was on Environmental and Natural Resource Economics. I have been working as an Economist in energy deliveries forecasting for the past 5 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	(Non-Price) Delivery Forecast by Market Segment and Service Level
1202	(Price Effect) Delivery Forecast by Market Segment and Service Level
1203	(Post Price & EE) Delivery Forecast by Market Segment and Service Level
1204	Forecast of Incremental Energy Efficiency Program Savings
1205	Residential Building Permits, New Connects, and Customer Counts (Accounts)
1206	Forecast of Residential Use per Customer and Ultimate Deliveries
1207	Commercial Deliveries Forecast by NAICS Cluster
1208	Manufacturing Deliveries Forecast by NAICS Cluster
1209	Forecast of Deliveries to Miscellaneous Rate Schedules
1210	Total Deliveries and Demand Forecast
1211	Forecast of 2016 Deliveries to Cost-of Service and Direct Access Customers

Delivery Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (not adjusted) Forecast (1)

	(in thousand MWh)					% Change (2)				
	2012	**2013**	**2014 (3)**	**2015**	**2016**	**2012**	**2013**	**2014**	**2015**	**2016**
Schedule 7	7,594	7,601	7,613	7,656	7,732	0.4%	0.1%	0.2%	0.6%	1.0%
Residential Lighting	7	7	5	4	4	-0.3%	-0.1%	-25.9%	-26.3%	0.0%
Total Residential	7,600	7,608	7,618	7,659	7,736	0.4%	0.1%	0.1%	0.5%	1.0%
Commercial	6,950	6,914	6,994	7,089	7,204	0.2%	-0.5%	1.2%	1.4%	1.6%
Manufacturing	4,493	4,540	4,616	4,841	4,761	1.4%	1.0%	1.7%	4.9%	-1.7%
Miscellaneous Customers	205	202	193	182	174	3.6%	-1.2%	-4.9%	-5.4%	-4.6%
Secondary Voltage	7,207	7,188	7,312	7,401	7,528	0.1%	-0.3%	1.7%	1.2%	1.7%
Total General Service	7,412	7,390	7,504	7,583	7,702	0.1%	-0.3%	1.5%	1.0%	1.6%
Primary Voltage Service	3,133	3,194	3,459	3,697	3,887	3.1%	1.9%	8.3%	6.9%	5.1%
Transmission Voltage Service	1,102	1,073	839	833	549	-2.1%	-2.7%	-21.9%	-0.7%	-34.0%
Total Retail	19,248	19,265	19,420	19,772	19,874	0.6%	0.1%	0.8%	1.8%	0.5%

1/ SDEC14B

2/ calculated from rounded numbers

3/ includes actual weather-adjusted values through December 2014 billing cycle

4/ by NAICS grouping

5/ Total Retail equals Total Residential + Commercial + Industrial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

Delivery Forecast (Price) by Market Segment and Service Level

(at average weather)

Net of Price Elasticity (1)

	(in thousand MWh)					% Change (2)				
	2012	2013	2014 (3)	2015	2016	2012	2013	2014	2015	2016
Schedule 7	7,594	7,601	7,613	7,652	7,699	0.4%	0.1%	0.2%	0.5%	0.6%
Residential Lighting	7	7	5	4	4	-0.3%	-0.1%	-25.9%	-26.3%	0.0%
Total Residential	7,600	7,608	7,618	7,655	7,702	0.4%	0.1%	0.1%	0.5%	0.6%
Commercial	6,950	6,914	6,994	7,088	7,196	0.2%	-0.5%	1.2%	1.3%	1.5%
Manufacturing	4,493	4,540	4,616	4,840	4,754	1.4%	1.0%	1.7%	4.9%	-1.8%
Miscellaneous Customers	205	202	193	182	174	3.6%	-1.2%	-4.9%	-5.4%	-4.6%
Secondary Voltage	7,207	7,188	7,312	7,399	7,516	0.1%	-0.3%	1.7%	1.2%	1.6%
Total General Service	7,412	7,390	7,504	7,581	7,690	0.1%	-0.3%	1.5%	1.0%	1.4%
Primary Voltage Service	3,133	3,194	3,459	3,696	3,885	3.1%	1.9%	8.3%	6.8%	5.1%
Transmission Voltage Service	1,102	1,073	839	833	549	-2.1%	-2.7%	-21.9%	-0.7%	-34.0%
Total Retail	19,248	19,265	19,420	19,766	19,826	0.6%	0.1%	0.8%	1.8%	0.3%

1/ SDEC14P

2/ calculated from rounded numbers

3/ includes actual weather-adjusted values through December 2014

4/ by NAICS grouping

5/ Total Retail equals Total Residential + Commercial + Industrial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

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)				
	2012	2013	2014 (3)	2015	2016	2012	2013	2014	2015	2016
Schedule 7	7,594	7,601	7,613	7,623	7,621	0.4%	0.1%	0.2%	0.1%	0.0%
Residential Lighting	7	7	5	4	4	-0.3%	-0.1%	-25.9%	-26.3%	0.0%
Total Residential	7,600	7,608	7,618	7,627	7,625	0.4%	0.1%	0.1%	0.1%	0.0%
Commercial	6,950	6,914	6,994	7,026	7,039	0.2%	-0.5%	1.2%	0.5%	0.2%
Manufacturing	4,493	4,540	4,616	4,829	4,724	1.4%	1.0%	1.7%	4.6%	-2.2%
Miscellaneous Customers	205	202	193	182	174	3.6%	-1.2%	-4.9%	-5.4%	-4.6%
Secondary Voltage	7,207	7,188	7,312	7,338	7,351	0.1%	-0.3%	1.7%	0.4%	0.2%
Total General Service	7,412	7,390	7,504	7,521	7,525	0.1%	-0.3%	1.5%	0.2%	0.1%
Primary Voltage Service	3,133	3,194	3,459	3,690	3,869	3.1%	1.9%	8.3%	6.7%	4.9%
Transmission Voltage Service	1,102	1,073	839	826	543	-2.1%	-2.7%	-21.9%	-1.4%	-34.3%
Total Retail	19,248	19,265	19,420	19,664	19,562	0.6%	0.1%	0.8%	1.3%	-0.5%

1/ SDEC14E

2/ calculated from rounded numbers

3/ includes actual weather-adjusted values through December 2014

4/ by NAICS grouping

5/ Total Retail equals Total Residential + Commercial + Industrial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

Forecast of Incremental Energy Efficiency (EE) Savings

(in thousand MWh)

	2015	2016
Base (B) Forecast	19,772	19,874
Price (P) Forecast	19,766	19,826
Incremental EE Savings (1)	(102)	(264)
Post-EE Forecast (E) (2)	19,664	19,562

1/ Energy Trust of Oregon (ETO) annual savings deployment forecast.

2/Totals and differences may not foot due to rounding.

Residential Building Permits, New Connects, Vacancy Rates and Customer Counts History and Forecast

	2012	2013	2014 (1, 2)	2015	2016
Building Permits (3)					
Single-Family	6,675	8,826	8,376	8,950	9,110
Multi-Family	4,409	5,504	7,437	6,437	7,045
New Connects					
Single-Family	2,942	3,240	3,257	3,332	3,539
Multi-Family	2,604	3,594	3,497	4,339	4,515
Mobile Home	26	29	47	24	36
Other	20	5	12	12	24
Total Residential Connects	5,592	6,868	6,813	7,706	8,114
Residential Customer Counts					
Single-Family Heat	109,071	109,123	109,246	109,383	109,476
Single-Family Non-Heat	345,461	347,878	350,673	353,341	355,745
Multiple-Family Heat	173,714	175,611	178,802	180,913	183,136
Multiple-Family Non-Heat	55,778	56,622	57,604	59,271	61,311
Mobile Home Heat	30,506	30,441	30,401	30,258	30,048
Mobile Home Non-Heat	3,882	3,873	3,886	3,886	3,861
Other	5,029	4,933	4,892	4,871	4,837
Total Number of Accounts (4)	723,440	728,481	735,502	741,924	748,413

1/ includes actuals through December 2014, except for building permits and connects which include actuals through November 2014 and October 2014, respectively

2/ forecasted values are identical for base, price-effect and energy efficiency forecast

3/ Oregon building permits

4/ includes vacant accounts

Forecast of Residential Use per Occupied Account and Ultimate Deliveries

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency (1)

	2012 (2)	2013 (2)	2014 (2, 3)	2015	2016
Use per Customer (kWh)					
Single-Family Heat	15,317	15,188	15,052	14,943	14,758
Single-Family Non-Heat	10,384	10,368	10,312	10,230	10,175
Multiple-Family Heat	8,468	8,356	8,302	8,298	8,238
Multiple-Family Non-Heat	6,080	6,105	6,074	6,029	6,004
Mobile Home Heat	14,148	14,132	13,993	13,937	13,821
Mobile Home Non-Heat	10,580	10,710	10,626	10,608	10,564
Other	10,516	10,587	10,561	10,803	10,885
Average Use per Customer	10,496	10,434	10,351	10,275	10,183
Ultimate Deliveries (million of kWh)					
Single-Family Heat	1,671	1,657	1,644	1,635	1,616
Single-Family Non-Heat	3,587	3,607	3,616	3,615	3,620
Multiple-Family Heat	1,471	1,467	1,484	1,501	1,509
Multiple-Family Non-Heat	339	346	350	357	368
Mobile Home Heat	432	430	425	422	415
Mobile Home Non-Heat	41	41	41	41	41
Other	53	52	52	53	53
Schedule 7 Deliveries	7,594	7,601	7,613	7,623	7,621
Residential Lighting	7	7	5	4	4
Total Residential Deliveries	7,600	7,608	7,618	7,627	7,625

1/ SDEC14E

2/ weather-adjusted

3/ includes actual weather-adjusted values through December 2014

Commercial Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change (1)				
	2012	2013	2014 (2)	2015 (3)	2016	2012	2013	2014	2015	2016
Food Stores	456	456	466	462	456	-0.7%	-0.1%	2.1%	-0.8%	-1.3%
Govt. & Education	988	977	995	993	1,001	-1.1%	-1.1%	1.8%	-0.2%	0.7%
Health Services	716	729	731	739	748	1.2%	1.8%	0.3%	1.1%	1.3%
Lodging	107	105	105	105	103	0.8%	-2.1%	-0.6%	0.4%	-2.0%
Misc. Commercial	658	635	639	639	637	-0.5%	-3.5%	0.7%	-0.1%	-0.2%
Department Stores/Malls	345	347	351	349	352	1.5%	0.5%	1.1%	-0.6%	0.9%
Office & F.I.R.E. (4)	1,022	1,033	1,050	1,055	1,057	0.8%	1.1%	1.7%	0.5%	0.2%
Other Services	823	801	803	809	804	0.8%	-2.6%	0.3%	0.8%	-0.7%
Other Trade	723	713	724	736	732	-1.6%	-1.4%	1.5%	1.7%	-0.5%
Restaurants	465	475	478	480	482	1.6%	2.2%	0.7%	0.2%	0.5%
Trans., Comm. & Utility	646	642	652	659	667	0.6%	-0.5%	1.5%	1.1%	1.1%
Total Commercial	6,950	6,914	6,994	7,026	7,039	0.2%	-0.5%	1.2%	0.5%	0.2%

1/ calculated using rounded-numbers

2/ includes actual weather-adjusted deliveries through December 2014

3/ forecasted values are price elasticity and incremental EE adjusted Forecast

4/ Finance, Insurance, and Real Estate

Manufacturing Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change (1)				
	2012	2013	2014 (2)	2015 (3)	2016	2012	2013	2014	2015	2016
Food & Kindred Products	220	224	236	228	217	3.9%	2.2%	5.2%	-3.4%	-4.8%
High Tech	1,915	1,941	2,142	2,313	2,445	3.0%	1.4%	10.3%	8.0%	5.7%
Lumber & Wood	98	99	98	100	102	0.4%	1.5%	-0.9%	2.2%	1.4%
Metal Manufacturing and Fab	512	500	493	494	493	-1.5%	-2.3%	-1.6%	0.2%	-0.1%
Other Manufacturing	652	681	750	780	825	4.5%	4.4%	10.1%	4.0%	5.8%
Paper & Allied Products	916	926	712	722	449	-2.3%	1.1%	-23.1%	1.4%	-37.8%
Transportation Equipment	181	168	185	192	193	0.9%	-7.2%	9.9%	3.7%	0.6%
Total Manufacturing	4,493	4,540	4,616	4,829	4,724	1.4%	1.0%	1.7%	4.6%	-2.2%

1/ calculated using rounded-numbers

2/ includes actual weather-adjusted deliveries through December of 2014 billing cycle

3/ price elasticity and incremental EE adjusted Forecast

Forecast of Deliveries to Miscellaneous Rate Schedules

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change (1)				
	2012	2013	2014 (2)	2015	2016	2012	2013	2014 (2)	2015	2016
Residential										
Outdoor Area Lighting (15R) (4)	7	7	5	4	4	-0.3%	-0.1%	-25.9%	-26.3%	0.0%
Secondary (Commercial)										
Outdoor Area Lighting (15C) (5)	16	16	15	13	13	-1.7%	-0.3%	-7.5%	-14.7%	0.0%
Farm Irrigation et al. (6)	78	78	80	82	84	10.2%	-0.7%	2.5%	3.3%	1.4%
Street and Other Lighting (7)	111	109	98	87	78	0.2%	-1.7%	-9.7%	-11.1%	-10.9%
Total Miscellaneous Commercial	205	202	193	182	174	3.6%	-1.2%	-4.9%	-5.4%	-4.6%
All Miscellaneous Schedules (8)	212	209	198	186	178	3.5%	-1.2%	-5.6%	-5.9%	-4.5%

1/ calculated from rounded numbers

2/ includes actual deliveries through December 2014 billing cycle

3/ identical for non-price, price-effect and post-EE forecasts

4/ existing Schedule 15R

5/ existing Schedule 15C

6/ existing Schedules 47 & 49

7/ existing Schedules 91, 92 & 93, and Schedule 95 beginning in 2013. Rate schedule 93 moved to Rate Schedule 38 in 2014.

8/ equals line 2 + line 7

Total Deliveries and Demand Forecast

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency (4)

	Million kWh (1)	Average MW (2)	Peak MW (3)
2009	19,165	2,309	3,949
2010	18,893	2,283	3,582
2011	19,138	2,316	3,555
2012	19,248	2,319	3,597
2013	19,265	2,339	3,869
2014	19,420	2,345	3,866
2015	19,664	2,390	3,604
2016	19,562	2,366	3,557

1/ cycle-month basis, at end-user meters; includes actual deliveries through December 2014

2/ calendar basis, at the bus bar, actual through 2014, not adjusted for weather.

3/ coincidental annual system peak at bus bar; includes actual through December 2014, not adjusted for weather.

4/ 2015 and 2016 are the price elasticity and incremental EE adjusted forecast.

Forecast of 2016 Deliveries to Cost of Service and Direct Access Customers

Net of Price Elasticity and Incremental Energy Efficiency

(in thousand MWh)

	Cost of Service (1)	Direct Access (2)	Total Delivery (3)
Residential	7,625	0	7,625
Secondary	6,995	453	7,448
Primary	3,063	807	3,869
Transmission	237	306	543
Lighting	78	0	78
Total Retail (2)	17,997	1,565	19,562

1/ Includes economic replacement VPO deliveries

2/ Schedule 485/489 deliveries.

3/ Totals may not add due to rounding.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Robert Macfarlane
Bruce Werner

February 12, 2015

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. Werner, for the development of the marginal cost studies.

My name is Bruce Werner. I am an 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, 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 subtransmission, substation, feeder backbone and tapline, transformers, service laterals, meters and customer service costs. Rate schedule changes are discussed in PGE Exhibit 1400.

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 requirements. This methodology is similar to the long-run methodology stipulated to in UE 283.

Q. Please describe the methodology stipulated to in UE 283.

A. In UE 283 we defined the long-run marginal generation resource as a combined cycle combustion turbine (CCCT) for baseload purposes. We used the fixed costs of an "F-class" simple cycle combustion turbine (SCCT) to estimate the portion of CCCT fixed costs to assign to capacity. We estimated marginal energy costs using the weighted values of the energy portion of the CCCT and a wind plant. We based the weightings on the renewable portfolio standard (RPS) requirements for each year. For example, the 2020 weighting is based on 20% wind and 80% thermal.

Q. Please describe the key differences between the study stipulated to in UE 283 and the current study.

A. The first difference between the studies is that the study stipulated to in UE 283 included environmental assumptions and the current study does not. We excluded the projected costs of carbon dioxide compliance from the thermal plant and the federal production tax credits from the wind plant. The second key difference is that we included fixed gas transportation as a capacity cost for the SCCT in this study whereas the study stipulated to in UE 283 assumed variable gas transportation.

Q. What type of SCCT did you use to estimate the marginal capacity costs?

A. Consistent with the methodology used to establish prices in the UE 283 stipulation, we use an "F-class" SCCT. This unit has lower capital costs than the LMS 100 and reciprocating engine units PGE presents in its recent Integrated Resource Plans (IRPs).

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 CCCT used for baseload purposes.
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 12% reserve requirements consistent with PGE's 2013 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. For the CCCT, we use the Carty Generating Station values used in this filing. For the SCCT, we obtained the location specific cost estimates for the SCCT from a publication titled "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants." This publication is sponsored by the United States Department of Energy. We include a copy of this publication in the Marginal Cost Work Papers. For the wind resource, we use the Tucannon River Wind Farm costs stipulated to in UE 283.

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 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.

Q. What is the source of your long-term gas price forecast?

A. We used the long-term gas price forecast dated November 2014 for the Sumas and AECO hubs. 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. Any potential carbon tax is uncertain. We also assumed no production tax credit for wind for the same reason.

Q. What is the fully allocated cost of the wind farm?

A. The cost of Tucannon River Wind Farm exclusive of wheeling is estimated at $66.51/MWh in real levelized 2016 dollars, consistent with the capital costs in UE 283.

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. In UE 283, the Citizens' Utility Board proposed a methodology for incorporating energy efficiency into the generation marginal cost study as an energy resource. Does your study reflect energy efficiency as a marginal energy resource?

A. No. In the stipulation in UE 283, parties agreed to support the opening of an investigatory docket to consider the appropriateness of including energy efficiency as a marginal energy resource in light of the requirements of Senate Bill 838. PGE intends to participate in that proceeding. We recognize that Commission determinations in that proceeding could impact our generation marginal cost study results in this case.

III. 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 2015-2019. We then annualize these capital expenditures and divide by the growth in system non-coincident peak. 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 (A) and (B) in PGE Exhibit 1301, 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 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), or 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 rate schedule based on the rate schedules' proportionate contribution to non-coincident peak (NCP). Calculate a unit cost per kW by totaling the feeder cost responsibilities and dividing by the sum of each schedule's NCP.
6. For each feeder, allocate the tapline cost responsibility of each rate schedule based on the rate schedules 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 (C) and (D) in PGE Exhibit 1301 summarize feeder mainline and tapline costs.

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). Primary delivery voltage customers don't incur the cost of a transformer, but do incur the cost of the facilities necessary to interconnect them to the distribution feeder. Service and design costs, and any wire costs not captured in the feeder portion of the study are included in these estimates. 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 (E) in PGE Exhibit 1301 summarizes transformer and service costs.

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 (F) 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 added to the per unit marginal capital cost. All of the distribution costs by functional category in PGE Exhibit 1301, Summary of Distribution and Customer Marginal Cost Studies, are inclusive of test-period distribution O&M.

Q. The UE 283 Second Partial Stipulation required PGE to perform a kilovolt-amperes reactive (KVAR) cost study and present the results at a pricing workshop prior to filing this general rate case. Has PGE met this requirement?

A. Yes, PGE presented the results of the KVAR cost study at the January 20, 2015 pricing workshop to representatives of the Oregon Public Utility Commission Staff, Kroger, and the Industrial Customers of Northwest Utilities. The results of the KVAR study demonstrated that PGE's current reactive demand charges for large nonresidential customers are appropriate, relative to the costs of mitigating reactive power. The specific calculations of the study are contained in the PGE Exhibit 1300 work papers.

IV. 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 to each customer class. 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.

Q. Does PGE use the forecasted test year expenses in the customer marginal cost study?

A. Yes. PGE uses forecasted costs for the 2016 test period and 2014 actual costs to develop the 2016 test year customer marginal costs (CMC). These costs are found in FERC Accounts 902, 903, 905, 908, and 909. The 2016 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 283?

A. Yes, the methodology is the same. As in UE 283, the costs are allocated by PGE accounts directly on the basis of cost causation. A few accounts are allocated based on a sub-allocation of the other account costs. After the costs are spread across rate schedules, the final result is marginal costs for each rate schedule by each of the three functionalized categories: metering, billing, and other services.

Q. Does this cost study identify a similar amount of costs relative to the cost study used in UE 283?

A. This cost study is improved by the inclusion of considerably more customer cost categories as allocators than the previous cost study. Inclusion of the addional categories affects the allocation percentages between the rate schedules. Schedule 89, for example, is allocated a lower percentage of costs relative to other rate schedules compared to UE 283.

Examples of Customer Marginal Cost Calculations

Q. Please provide an example of how you calculate metering marginal costs.

A. The 2016 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.

V. Area and Streetlights

Q. Please describe the changes you propose in the pricing of Area Lights and Streetlights.

A. We propose to price the investment portion (poles and luminaires) of providing lighting service using a real levelized annual revenue requirement rather than nominal. This change reduces the investment cost by removing the effects of inflation and is consistent with the methodology used in our other marginal cost studies.

Q. Please describe how you calculate the amount of outdoor lighting maintenance.

A. Similar to UE 283, we propose to base the test period lighting maintenance amount on the incurred maintenance amounts during PGE's most recent 5-year re-lamping cycle (2005-2009). 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. How do the maintenance amounts calculated in the marginal cost study compare to the maintenance amounts calculated using the historical re-lamping cycle as a base?

A. The amounts are close; the total amount of maintenance proposed for the 2016 test period – based on the historical re-lamping cycle – is approximately $229,000 lower than the amount calculated in the marginal cost study.

Q. Do you provide a summary exhibit of the proposed pole and luminaire prices?

A. Yes. This summary is provided in PGE Exhibit 1406.

VI. Qualifications

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

A. I received a Bachelor of Arts business degree from Portland State University with a focus in finance. Since joining PGE in 2008, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have included pricing, revenue requirement, Public Utility Regulatory Policies Act avoided costs, and regulatory issues. From 2004 to 2008, I was a consultant with Bates Private Capital in Lake Oswego, OR, where I developed, prepared, and reviewed financial analyses used in securities litigation.

Q. Mr. Werner, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree with an emphasis in Fine Arts from Montana State University in 1977. Since joining PGE in 1999 I have worked as an analyst on a variety of pricing issues and cost studies in the Rates and Regulatory Affairs Department. From 1979 to 1999 I worked at PacifiCorp in several different capacities starting with Weatherization and Energy Efficiency programs and finishing as a Senior Cost of Service Analyst in their Rates and Regulatory Affairs Department.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1301	Marginal Cost Study

PORTLAND GENERAL ELECTRIC
2016 MARGINAL ENERGY COSTS

Schedule	Busbar Energy (MWh)	Marginal Energy Cost
Schedule 7	8,141,584	$401,864,226
Schedule 15	17,425	$792,164
Schedule 32	1,711,772	$83,982,444
Schedule 38	41,909	$2,104,884
Schedule 47	22,135	$1,115,665
Schedule 49	67,115	$3,268,684
Schedule 83	2,992,243	$146,402,339
Schedule 85 201- 1,000 kW	2,412,281	$118,430,943
Schedule 85 1-4 MW	967,084	$47,281,555
Schedule 89 GT 4 MW	977,909	$47,132,916
Schedule 90-P	1,578,439	$75,881,616
Schedule 91/95	79,651	$3,621,007
Schedule 92	3,465	$166,109
Totals	19,013,012	$932,044,551

PORTLAND GENERAL ELECTRIC
2016 UNIT MARGINAL ENERGY AND CAPACITY COSTS

Year	Thermal Capacity SCCT $/kW-year	SCCT Fixed Gas Transport $/kW-year	VERBS $/kW-year	Thermal Capacity $/kW-year	Wind Capacity w VERBS $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Weighted Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2016	83.86	40.60	14.68	124.46	139.14	43.26	66.51	15.00%	126.66	46.74
2017	85.48	41.38	14.96	126.86	141.82	44.09	67.80	15.00%	129.11	47.65
2018	87.13	42.18	15.25	129.31	144.56	44.94	69.10	15.00%	131.60	48.57
2019	88.81	43.00	15.54	131.81	147.35	45.81	70.44	15.00%	134.14	49.50
2020	90.52	43.83	15.84	134.35	150.19	46.69	71.80	15.00%	136.73	50.46
2021	92.27	44.67	16.15	136.94	153.09	47.59	73.18	20.00%	140.17	52.71
2022	94.05	45.53	16.46	139.59	156.05	48.51	74.60	20.00%	142.88	53.73
2023	95.87	46.41	16.78	142.28	159.06	49.45	76.03	20.00%	145.64	54.77
2024	97.72	47.31	17.10	145.03	162.13	50.40	77.50	20.00%	148.45	55.82
2025	99.60	48.22	17.43	147.82	165.26	51.38	79.00	20.00%	151.31	56.90
2026	101.52	49.15	17.77	150.68	168.45	52.37	80.52	25.00%	155.12	59.41
2027	103.48	50.10	18.11	153.59	171.70	53.38	82.08	25.00%	158.11	60.55
2028	105.48	51.07	18.46	156.55	175.01	54.41	83.66	25.00%	161.17	61.72
2029	107.52	52.05	18.82	159.57	178.39	55.46	85.28	25.00%	164.28	62.91
2030	109.59	53.06	19.18	162.65	181.83	56.53	86.92	25.00%	167.45	64.13
2031	111.71	54.08	19.55	165.79	185.34	57.62	88.60	25.00%	170.68	65.37
2032	113.86	55.13	19.93	168.99	188.92	58.73	90.31	25.00%	173.97	66.63
2033	116.06	56.19	20.31	172.25	192.57	59.87	92.05	25.00%	177.33	67.91
2034	118.30	57.27	20.71	175.58	196.28	61.02	93.83	25.00%	180.75	69.22
2035	120.58	58.38	21.11	178.96	200.07	62.20	95.64	25.00%	184.24	70.56
Real Levelized	$83.86	$40.60	$14.68	$124.46	$139.14	$43.26	$66.51		$127.44	$47.97
NPV	$1,078	$522	$189	$1,600	$1,788	$556	$855		$1,638	$617
Nominal Levelized	$97.30	$47.11	$17.03	$144.41	$161.44	$50.19	$77.17		$147.87	$55.66
Real Levelized	$83.86	$40.60	$14.68	$124.46	$139.14	$43.26	$66.51		$127.44	$47.97

Composite Income Tax Rate			39.94%
Property Tax Rate			1.50%
Inflation Rate			1.93%
Capitalization:			
Preferred	0.00%	0.00%	0.00%
Common	50.00%	9.75%	4.88%
All Equity	50.00%		4.88%
Debt	50.00%	5.77%	2.89%
Cost of Capital			7.76%
After-Tax Nominal Cost of Capital			6.61%
After-Tax Real Cost of Capital			4.59%

PORTLAND GENERAL ELECTRIC
SUMMARY OF DISTRIBUTION AND CUSTOMER MARGINAL COST STUDIES

SCHEDULE	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)
Schedule 7 Residential							
Single-phase	$12.38	$11.39	$23.97	$16.18	$73.98	$20.22	$68.88
Three-phase	$12.38	$11.39	$23.97	$16.18	$130.73	$57.47	$68.88
Schedule 15 Residential	$12.38	$11.39	$24.76	$16.86	$5.44	N/A	$68.24
Schedule 15 Commercial	$12.38	$11.39	$24.76	$16.86	$5.44	N/A	$54.45
Schedule 32 General Service							
Single-phase	$12.38	$11.39	$27.91	$23.61	$105.18	$18.32	$70.46
Three-phase	$12.38	$11.39	$27.91	$9.43	$224.71	$70.94	$70.46
Schedule 38 TOU							
Single-phase	$12.38	$11.39	$34.05	$19.37	$149.42	$52.41	$321.36
Three-phase	$12.38	$11.39	$34.05	$13.45	$507.27	$125.41	$321.36
Schedule 47 Irrigation							
Single-phase	$12.38	$11.39	$73.00	$49.64	$10.05	$57.42	$76.64
Three-phase	$12.38	$11.39	$73.00	$25.88	$19.03	$81.34	$76.64
Schedule 49 Irrigation							
Single-phase	$12.38	$11.39	$76.09	$32.76	$130.10	$59.88	$135.67
Three-phase	$12.38	$11.39	$76.09	$26.05	$130.10	$69.56	$135.67
Schedule 83 Secondary General Service							
Single-phase	$12.38	$11.39	$24.36	$19.94	$334.66	$52.33	$223.57
Three-phase	$12.38	$11.39	$24.36	$8.96	$937.19	$124.16	$223.57
Schedule 85 Secondary General Service	$12.38	$11.39	$20.95	$6.84	$1,840.38	$163.10	$886.26
Schedule 85 Primary General Service	$12.38	$11.39	$20.95	$6.84	$727.30	$1,781.36	$886.26
Schedule 85 Secondary 1-4 MW	$12.38	$11.39	$21.35	$4.89	$4,112.80	$186.22	$886.26
Schedule 85 Primary 1-4 MW	$12.38	$11.39	$21.35	$4.89	$864.59	$1,794.23	$886.26
Schedule 89 Secondary GT 4 MW	$12.38	$11.39	($/Customer) $85,119	N/A	$13,785.61	$195.47	$5,397.96
Schedule 89 Primary GT 4 MW	$12.38	$11.39	($/Customer) $85,119	N/A	$2,566.49	$1,785.30	$5,397.96
Schedule 89 Subtransmission	$12.38	N/A	($/Customer) $86,451	N/A	N/A	$17,752.55	$5,397.96
Schedule 90 Primary	$12.38	$11.39	($/Customer) $269,070	NA	$2,566.49	$1,773.01	$17,983.50
Schedules 91 & 95 Streetlighting	$12.38	$11.39	$24.76	$16.86	$3.28	N/A	$945.99
Schedules 92 Traffic Signals	$12.38	$11.39	$24.76	$9.16	$8.06	N/A	$829.74

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Marc Cody

February 12, 2015

Table of Contents

I. Introduction and Summary

Q. Please state your name and position.

A. My name is Marc Cody. I am a Senior Analyst in Pricing and Tariffs for PGE. My qualifications are described in Section V.

Q. What is the purpose of your testimony?

A. My testimony and accompanying exhibits demonstrate how the proposed E-18 Tariff changes recover Portland General Electric's (PGE) 2016 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, my testimony also describes the revenue requirement allocation process (ratespread), and the rate design. I also discuss the proposal to price the irrigation Schedules 47 and 49 in a manner that will enable them to be more seamlessly integrated into Schedules 32 and 38 respectively, after PGE implements a new billing system. Finally, I discuss the price changes to various supplemental schedules. Included in these supplemental schedules are Schedule 102 Regional Power Act Exchange Credit, Schedule 105 Regulatory Adjustments, Schedule 123 Decoupling Adjustment, Schedule 143 Spent Fuel Adjustment, and Schedule 144 Capital Projects Adjustment.

Q. Please summarize the projected Cost of Service (COS) rate impacts resulting from the proposed allocations.

A. Table 1 below summarizes the rate impacts for the major rate schedules as well as the overall rate impacts with and without direct access (DA) customers. These rate impacts include changes in the supplemental schedules mentioned above, and the impacts of the Carty Generating Station (Carty) that PGE proposes to include in rates during 2016. The rate impacts from Carty and the proposed January 1, 2016 changes are provided separately within Table 1. PGE Exhibit 1402 contains more detailed information on the rate impacts for the individual schedules. Tables 1 through 4 of PGE Exhibit 1402 contain the impacts of the proposed prices effective January 1, 2016, including the proposed base rate changes effective January 1, 2016. Table 5 builds from Table 4 and reflects both the proposed January 1 price changes and the incremental impacts of Carty relative to current prices. The detailed bill impacts contained in PGE Exhibit 1402 relate to prices effective January 1, 2016. I include in the work papers detailed bill impacts with the proposed prices for Carty.

Table 1
Estimated Cost of Service Rate Impacts

Schedule	Jan. 1, 2016	Carty	Total
Schedule 7 Residential	-1.2%	4.3%	3.1%
Schedule 32 Small Nonresidential	1.8%	4.2%	6.0%
Schedule 83 31-200 kW	0.4%	5.0%	5.3%
Schedule 85 201-4,000 kW	-1.6%	5.5%	3.9%
Schedule 89 Over 4,000 kW	-2.3%	6.3%	4.0%
Schedule 90 100 MWa	-1.7%	6.6%	4.9%
COS Overall	-0.7%	4.7%	4.0%
COS & DA Overall	-1.0%	4.7%	3.7%

II. Ratespread

Q. Please summarize the changes in ratespread, rate design, and tariff language you have made since PGE's last general rate case, Docket No. UE 283.

A. The key changes I propose are listed below (and explained later in testimony):

- Price the small nonresidential Schedules 32 and 47 in a manner that will allow for the customers currently on Schedule 47 to be moved to Schedule 32 at a future date in a manner that greatly reduces the future impact of such a change to customers. This is proposed in order to achieve future administrative cost efficiencies and to lessen the burden on other customers, including residential customers, of continuing to subsidize Schedule 47 prices.
- Similar to the proposal for Schedules 32 and 47, price Schedules 38 and 49 in a manner that will allow for a more seamless consolidation of Schedule 49 and Schedule 38 at a future date. The customers on these rate schedules tend to have consumption that is seasonal with low annual load factors. Hence, it makes sense to eventually consolidate these two large nonresidential schedules, both of which do not have demand charges.
- Incorporate language changes into the Special Conditions of Schedules 75 and 575 Partial Requirements Service that allows for a more balanced determination of the appropriate Baseline Demand.

Q. Do you propose changes other than prices to existing supplemental schedules?

A. No, although the proposed price changes for Schedule 143 result partially from accelerating the amortization of the refund to customers related to the settlement of decommissioning expenses for the Trojan nuclear plant.

Q. What is the basis for the functional allocation of costs to the rate schedules?

A. I use the Marginal Cost of Service Study to guide the allocation of the generation, distribution, and customer service (separately, Metering, Billing, and Other Consumer Service) functional revenue requirements in the rate spread process. The Marginal Cost Study is presented in PGE Exhibit 1300.

Q. How do you calculate and allocate the 2016 test-period marginal generation capacity costs to the individual rate schedules?

A. To obtain the marginal capacity costs, I multiply the real levelized annual capacity cost described in PGE Exhibit 1300 by the projected 2016 COS test-period peak-hour load. This peak-hour load is projected to occur in December. I then allocate the marginal 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. I choose these four months because they are the months with the highest peaks consistent with the periods identified as capacity deficient in the 2013 Integrated Resource Plan. Additionally, I choose these four months because PGE's highest annual peak hours generally occur during one of these four months.

Q. What are the respective capacity and energy percentages used in allocating the generation revenue requirements?

A. Capacity comprises approximately 31.5% of the marginal cost of generation, and energy approximately 68.5%. The corresponding figures from UE 283 were approximately 25% and 75%.

Q. How do you allocate the costs of Carty?

A. I allocate the costs of Carty to the COS rate schedules on the basis of the projected test period COS energy revenues before including Carty. These COS energy revenues are based on the generation marginal cost estimation contained in PGE Exhibit 1300, hence a consistent allocation of generation costs is achieved. A summary of the cost allocation of Carty is presented in PGE Exhibit 1405.

Q. How will the price changes for Carty be implemented?

A. After the Commission rules on the test-period revenue requirements for Carty, PGE will implement changes in the COS Energy Charges and the Schedule 128 and 129 Transition Adjustments as appropriate through an Advice Filing. Because changes in Schedule 129 revenues impact either Distribution Charges or System Usage Charges, PGE will include these changes in the filing. PGE will also file for the appropriate changes in Schedule 123 Decoupling Adjustment to reflect the increases in fixed costs.

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, I allocate it in the same manner as I do generation. I allocate the transmission revenue requirement consistent with how PGE's FERC transmission prices are determined, therefore on a twelve coincident peak basis (12-CP). These two functional categories combined with the five 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. I allocate franchise fees to the schedules on the basis of the test period revenue requirement allocations and Trojan decommissioning on a generation revenues basis. I allocate Schedule 129 Long-Term Transition Adjustment for enrollment periods A through K to Schedule 85, 89, and 90 customers on an energy basis, with subsequent enrollment periods allocated on an energy basis to all schedules. This allocation is consistent with the Partial Stipulation in UE 262. Finally, I allocate uncollectible expense based on historical incidence for the years 2012-2014. 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. I allocate the franchise fee revenue requirements in the same manner as in UE 283. Therefore, I do not attribute cost responsibility for the generation and transmission functional categories to direct access customers. More specifically, I 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, I 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 a system usage charge, I 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, <u>after</u> spreading the revenue requirements, I apply the Customer Impact Offset (CIO) in order to temper the rate impacts to certain schedules. Specifically, I limit the combined base rate increase for Schedules 38 and 49 to 12% before consideration of Carty. The CIO is discussed in more detail later in testimony.

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 kilowatt (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, 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 much higher customer charges.

Q. What principles do you consider in developing the proposed prices?

A. I 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. I 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 prices for Schedule 7, Residential Service.

A. The prices are summarized below:

Table 2
Schedule 7
Residential Service Proposed Prices

Category	Prices
Basic Charge	$11.00 per customer per month
Transmission & Related Service Charge	2.43 mills per kWh
Distribution Charge	41.00 mills per kWh
Energy Charge First 1,000 kWh	65.24 mills per kWh
Energy Charge Over 1,000 kWh	72.46 mills per kWh

Q. Please explain how you develop these prices.

A. Although the embedded customer costs suggest a **Basic Charge** of approximately $22, and the marginal customer costs sum to more than $13, I propose to increase the Basic Charge by one dollar, to $11 in order to better match prices to costs, consistent with the principles discussed above.

I develop the **Transmission & Related Service Charge** directly from the allocated transmission and ancillary services revenue requirement.

I calculate the **Distribution Charge** of 41.00 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.

I 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. I 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 $157,000. I incorporate this impact in the standard Schedule 7 energy charge.

Q. Please list the individual 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	$16.00 per customer per month
Basic Charge Three Phase	$22.00 per customer per month
Transmission & Related Services Charge	2.10 mills per kWh
Distribution Charge First 5,000 kWh	40.49 mills per kWh
Distribution Charge Over 5,000 kWh	9.99 mills per kWh
Energy Charge	62.30 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, I increase the Basic Charge for single- and three-phase service to $16.00 and $22.00 per month from their current levels of $15.00 and $20.00 respectively. These basic charges are still considerably below the embedded customer-related costs of approximately $26 and $45. As with Schedule 7, I capture the difference between the allocated costs and the various revenues within the Distribution Charge.

I compute the **Transmission and Related Services Charge** directly from the allocated transmission and ancillary service costs.

I retain the current Schedule 32, **Distribution Charge** blocking, with the initial block including usage up to 5,000 kWh. I 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, I include within the Distribution Charge the costs associated with franchise fees and Trojan Decommissioning.

I 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. I 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 $54,000. I 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 transmission and 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. I 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. I use the same approach and cost causation principles as described for Residential and Small Nonresidential service in designing these rates. 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	$0.79	per on-peak kW
Distribution Demand Charge	$2.38	per on-peak kW
Facility Capacity Charge (First 30 kW)	$2.85	per kW Facility Capacity
Facility Capacity Charge (Over 30 kW)	$2.75	per kW Facility Capacity
System Usage Charge	8.74	mills per kWh
COS Energy Charge On-peak	66.66	mills per kWh
COS Energy Charge Off-peak	51.66	mills per kWh

Q. Please describe how you develop the Schedule 83 prices.

A. I 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. Similar to Schedule 32, these basic charges are set considerably below the marginal 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, I set the **Transmission & Related Service Charge** to $0.79 per kW of on-peak demand consistent with the other secondary voltage customers served on Schedules 85 or 89. I do this to make the pricing more consistent for customers who choose Direct Access Service under Schedules 583, 585, 589, or 590. This charge results in more than a full recovery of Schedule 83 allocated costs, consequently I 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**. I recover the costs associated with the 13 kV system through the Facility Capacity Charge. I set the Facility Capacity Charge for the first 30 kW at a higher level 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.

I set the **Demand Charge** which recovers distribution substations and 115 kV costs where applicable, at $2.38 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, I 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.

I calculate the COS Energy Charges based on the results of the generation allocations. I maintain the on-and off-peak differential at the current 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.

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.

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 I discuss below. I 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 below:

Table 5
Schedule 85 General Service 201-4,000 kW

Category	Secondary Prices		Primary Prices	
Basic Charge	$430.00	per customer per month	$460.00	per customer per month
Trans. & Related Services	$0.79	per on-peak kW	$0.77	per on-peak kW
Distribution Demand Charge	$2.38	per on-peak kW	$2.32	per on-peak kW
Facility Capacity Charge (First 200 kW)	$3.01	per kW Facility Capacity	$2.94	per kW Facility Capacity
Facility Capacity Charge (Over 200 kW)	$2.11	per kW Facility Capacity	$2.04	per kW Facility Capacity
System Usage Charge	1.20	mills per kWh	1.16	mills per kWh
COS Energy Charge On-peak	64.97	mills per kWh	63.87	mills per kWh
COS Energy Charge Off-peak	49.97	mills per kWh	48.87	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, I set the Basic Charges at $430 and $460 per month, respectively. The secondary voltage customer charge, subject to rounding, recovers the full amount of the allocated customer-related costs. I set the primary voltage customer charge $30 per month higher, consistent with the current price differential. These customer charges combined with the declining block facilities charges help transition those Schedule 83 customers whose demand grows to exceed 200 kW.

For Schedules 83, 85, 89 and 90, I set the **Transmission & Related Service Charge** to $0.79 per kW of on-peak demand for secondary service, and to $0.77 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, I recover the costs associated with the 13 kV system through the Facility Capacity Charge. The difference between secondary and primary voltage Facility Capacity Charges reflect the difference in estimated peak demand losses for the respective delivery voltages. The facilities charge also recovers any over- or under-recovery of the other charges.

The **Demand Charges** of $2.38 and $2.32 for secondary and primary voltage customers respectively are set in conjunction with the demand charges for schedules 83, 89, and 90 as discussed earlier. I 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, I separately state the **System Usage Charge** which recovers franchise fees, Trojan Decommissioning costs, and the CIO. I also use this charge for Schedules 83, 85, 89, and 90 to capture the Schedule 129 transition adjustment and the generation fixed cost contributions 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.

I calculate the COS energy charges based on the results of the generation allocations. I maintain the on- and off-peak differential at 15 mills/kWh. I 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.

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 below:

Table 6
Schedule 89 General Service Greater than 4,000 kW

Category	**Secondary Prices**	**Primary Prices**	**Subtransmission Prices**
Basic Charge	$2,670.00 per month	$1,620.00 per month	$3,090.00 per month
Transmission & Related Charge	$ 0.79 per on-peak kW	$0.77 per on-peak kW	$0.76 per on-peak kW
Facility Capacity Charge First 4,000 kW	$0.99 per kW Facility Capacity	$0.96 per kW Facility Capacity	$0.96 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$0.99 per kW Facility Capacity	$0.96 per kW Facility Capacity	$0.96 per kW Facility Capacity
Distribution Demand Charge	$2.38 per on-peak kW	$2.32 per on-peak kW	$1.21 per on-peak kW
System Usage Charge	0.83 mills per kWh	0.80 mills per kW	0.77 mills per kW
COS Energy Charge On-peak	64.09 mills per kWh	63.04 mills per kWh	62.25 mills per kWh
COS Energy Charge Off-peak	49.09 mills per kWh	48.04 mills per kWh	47.25 mills per kWh

Q. Please describe how you develop the Schedule 89 Charges.

A. I set the **Basic Charges** for secondary, primary and subtransmission voltage customers at 100% of the customer-related costs for each delivery voltage. The proposed Schedule 89 **Basic Charges** are considerably less than the current charges due to the lower customer-related and uncollectible costs allocated to Schedule 89 relative to UE 283. The reason for the lower allocation of customer-related costs is discussed in PGE Exhibit 1300.

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.

The **Distribution Demand Charge** is also calculated 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 one cent/kW is added to the Distribution Demand Charge to equalize the Facility Capacity Charge for primary voltage and subtransmission voltage delivery. As with Schedule 85, I 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. I propose the same price for both blocks, similar to how Schedule 90, which is discussed below, is priced. The Facility Capacity Charges reflect the peak demand loss difference between providing service at secondary or primary voltage service. As mentioned above, I 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. I 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 85/585, Schedules 89 and 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 below:

Table 7
Schedule 90 General Service Greater than 4,000 kW aggregating to 100 MWa

Category	**Primary Voltage Prices**
Basic Charge	$25,000.00 per month
Transmission & Related Charge	$0.77 per on-peak kW
Facility Capacity Charge First 4,000 kW	$0.97 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$0.97 per kW Facility Capacity
Distribution Demand Charge	$2.32 per on-peak kW
System Usage Charge	0.67 mills per kW
COS Energy Charge On-peak	60.27 mills per kWh
COS Energy Charge Off-peak	45.27 mills per kWh

Q. Please describe how you develop the Schedule 90 Charges.

A. I set the **Basic Charge** at a level exceeding the normal customer cost categories because of the large size of the accounts on this schedule and because it is reasonable to think of the distribution feeders for very large customers as a customer-related cost.

Similar to Schedule 89, I 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, I use the Facility Capacity Charge to recover the remainder.

The **Distribution Demand Charge** is also calculated in conjunction with Schedules 83, 85, and 89. Any under-collection of costs is recovered through the Facility Capacity Charge.

I set the **Facility Capacity Charge** on a flat basis and flow through any over- or under-recovery of allocated 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 option similar to those for Schedules 85 and 89.

Q. Do you propose to continue the load following/integration credit for Schedule 90 stipulated to in UE 262 and carried forward in UE 283?

A. Yes, I propose to continue this, applicable to 150 MWa compared to the 140 MWa used in UE 283. The higher amount is due to projected load growth. This credit amount of $1.5 million will continue to be incorporated into the base energy charges for Schedule 90 customers. This $1.5 million is allocated solely to Schedule 89 customers and recovered through the base energy charges in order to better equalize the base rate price impacts across the major rate schedules.

Q. Please discuss how you priced the irrigation 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. I propose the current monthly $25 Basic Charge for single- and three-phase service customers. I 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. In order to achieve cost efficiencies, PGE hopes to consolidate Schedules 38 and 49 in a subsequent general rate case; hence I calculate the prices for both of these schedules as if they were one schedule. However, to minimize the amount of billing programming logic changes, I retain the current structural elements for Schedules 38 and 49. Therefore, as mentioned above, Schedule 38 retains its TOU energy pricing, while the Schedule 49 energy charge is flat across all hours. Schedule 49 retains its blocked distribution pricing, although I propose to reduce the block differentials from the current 20 mills/kWh to 10 mills/kWh in order to facilitate a more orderly future consolidation with Schedule 38. Finally, I propose that the customer charge for Schedule 49 continue to be applicable six months of the year, but at a level that is twice the proposed customer charge for Schedule 38, therefore $50. Both Schedules 38 and 49 have direct access equivalent schedules; Schedules 538 and 549 respectively.

Schedule 47, Irrigation and Drainage Pumping Small Nonresidential Standard Service, applies to Small Nonresidential customers whose demand does not exceed 30 kW. Similar to what I propose for Schedule 38 and 49, I price Schedules 32 and 47 as if they were one rate schedule, but I retain the unique characteristics of each schedule in order to minimize the amount of billing logic changes needed under the current billing system. In addition, I price Schedule 47 in a manner such that the sum of its volumetric prices is similar to its large nonresidential counterpart, Schedule 49. If I priced Schedule 47 with the criteria specified above without taking into consideration the Schedule 49 prices, Schedule 47 would have much lower prices than Schedule 49. This would potentially create an awkward situation where Schedule 49 customers might request to be billed at Schedule 47 prices. Pricing Schedule 47 with consideration of the Schedule 49 prices also lessens the burden placed on Schedule 32 customers.

I retain the Schedule 47 blocked distribution prices with the block differential decreasing from 20 mills/kWh to 10 mills/kWh. I increase the monthly Basic Charge to $44 per month for the six summer months only, a level that is twice that of the proposed Schedule 32 three-phase basic charge. Schedule 47 customers may take Direct Access Service under Schedule 532.

Q. How do your proposals for the irrigation schedules generally impact the irrigation schedules and the other rate schedules?

A. The Schedule 47 base rate impact before Carty is near zero. Not surprisingly, the prices for Schedule 32 are approximately one percent higher than they would otherwise be. Other rate schedules are positively impacted because they no longer carry the burden of mitigating the price increase for Schedule 47.

Schedule 49 continues to be heavily subsidized and because of the shared pricing with Schedule 38, the prices for Schedule 38 are higher than they would otherwise be. The discussion of rate impact mitigation for Schedules 38 and 49 is below.

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:

I 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 91/591 and 95/595, Street and Highway Lighting Standard Service, provides 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. I 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. Please describe why you propose to change one of the Special Conditions contained in Schedules 75 and 575.

A. I propose to change Special Condition 8 for Schedule 75 (and Special Condition 7 for Schedule 575) because the current Schedule 75 Special Conditions leave it solely at the discretion of the customer to initiate changes in Baseline Demand. The proposed changes provides PGE with the necessary discretion to initiate a change should PGE determine that the level of Baseline Demand not reflect the customer's load adjusted for actual generation.

Q. Why and how do you limit the amount of increase to some rate schedules?

A. The pricing for Schedules 38 and 49 is established at rates that are significantly less than the cost to serve. If I were to price these schedules at cost, they would experience extremely large rate increases. I therefore propose to limit the combined impacts of Schedules 38 and 49 to no more than a 12% percent base rate increase before consideration of Carty. Over time, PGE hopes to gradually move these schedules closer to cost of service while gradually sending the appropriate price signal.

Q. Which schedules bear the costs of mitigation of the schedules mentioned above?

A. I propose that Schedules 83 and 85 bear the mitigation burden in proportion to the Schedule 49 historical consumption of customers below or above 200 kW. To elaborate, approximately 93% of Schedule 49 consumption during 2014 was by customers between 31 and 200 kW and the remaining 2014 consumption was by customers whose demand exceeded 200 kW. Hence I propose that the mitigation burden be borne in these proportions by customers on Schedules 83 and 85 and their direct access equivalents.

Q. How do you implement the CIO mitigation?

A. I increase the System Usage Charges for Schedules 83 and 85 to offset the effect of the price mitigation efforts described above. Schedules 38 and 49 receive the CIO subsidy through their distribution charges. I also use the CIO to equalize the distribution charges for the outdoor lighting schedules 15, 91, and 95. PGE Exhibit 1404 shows the development of this offset.

Q. Compared to UE 283, has the proposed amount of the CIO subsidy increased or decreased?

A. It has decreased. The UE 283 CIO subsidy to Schedules 47 and 49 was approximately $8.5 million, while the proposed subsidy to Schedules 38 and 49 is approximately $5.2 million. This reduction is due in part by pricing Schedule 32 and 47 in the manner discussed above and also in part by the recent successive price increases to Schedule 49.

IV. Other Rate Schedule Changes

Q. What do you estimate for 2016 Regional Power Act Exchange benefits?

A. Based on the Bonneville Power Administration's draft Average System Cost report for fiscal years 2016-2017, I estimate annual benefits of approximately $65 million. This is an increase in benefits of approximately $15 million to eligible PGE customers. I propose to incorporate the change in benefits and the appropriate level of balancing account amortization through a Schedule 102 Advice filing to occur in November with prices effective January 1, 2016.

Q. What is prompting the estimated change to Schedule 105 Regulatory Adjustments?

A. The gains from prior property sales should be amortized by the end of 2015; hence I remove this credit to customers from the Schedule 105 calculation. I also remove the charge associated with the Independent Evaluator costs incurred during the 2011-2013 period, and the credit for the Large Nonresidential True-Up. The net economic benefit associated with the Power Resources Cooperative share of the Boardman plant is left in the calculation for determining 2016 prices. The estimated change in Schedule 105 prices is an increase in revenues of approximately $6.7 million. The Schedule 105 prices will be updated later in the year when more information becomes available regarding various miscellaneous deferrals.

Q. What changes in Schedules 123 prices do you presume for 2016?

A. For the Sales Normalization Adjustment portion of Schedule 123, I provide an estimate of the Schedule 123 prices that include activity through December 2014. For both Schedules 7 and 32, Schedule 123 will be a credit, effective January 1, 2016. I presume that the Lost

Revenue Recovery Adjustment portion of Schedule 123 will be zero. The estimated change in Schedule 123 prices results in a decrease in revenues of approximately $11.0 million.

Q. What 2016 changes do you propose for Schedule 143?

A. I set the Part B Independent Spent Fuel Storage Installation portion to zero for 2016 and I accelerate the Department of Energy refund such that it should be fully amortized by the end of 2016 rather than 2017 as originally planned. This accelerated amortization is also discussed in PGE Exhibit 100. The result of the changes in Schedule 143 prices is a decrease in revenues of approximately $11.0 million.

Q. What do you propose for Schedule 144?

A. Because the deferred costs for the four capital projects should be fully amortized by the end of 2015, I propose to set the prices to zero effective January 1, 2016. This results in a decrease in revenues of approximately $26.2 million.

Q. How will the changes in the supplemental schedules above be implemented?

A. The price changes will be implemented through various Advice Filings, made in October and November 2015.

V. 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. 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	Allocation of Carty Costs
1406	Streetlight and Area Lights

Advice No. 15-02
Portland General Electric General Rate Revision
Revised Tariff Sheets filed February 12, 2015

Eighth Revision of Sheet No. 7-1
Sixth Revision of Sheet No. 15-1
Seventh Revision of Sheet No. 15-2
Seventh Revision of Sheet No. 15-3
Seventh Revision of Sheet No. 15-4
Fifth Revision of Sheet No. 15-5
Third Revision of Sheet No. 15-6
Seventh Revision of Sheet No. 32-1
Seventh Revision of Sheet No. 32-4
Seventh Revision of Sheet No. 38-1
Ninth Revision of Sheet No. 38-3
Seventh Revision of Sheet No. 47-1
Eighth Revision of Sheet No. 49-1
Tenth Revision of Sheet No. 75-1
Sixth Revision of Sheet No. 75-5
First Revision of Sheet No. 75-8
Tenth Revision of Sheet No. 76R-1
Sixth Revision of Sheet No. 76R-3
Sixth Revision of Sheet No. 76R-4
Sixth Revision of Sheet No. 76R-5
Seventh Revision of Sheet No. 81-1
Ninth Revision of Sheet No. 83-1
Tenth Revision of Sheet No. 83-2
Sixth Revision of Sheet No. 85-1
Sixth Revision of Sheet No. 85-2
Tenth Revision of Sheet No. 89-1
Tenth Revision of Sheet No. 89-2
Second Revision of Sheet No. 90-1
Second Revision of Sheet No. 90-2
Tenth Revision of Sheet No. 91-7
Eighth Revision of Sheet No. 91-9
Seventh Revision of Sheet No. 91-10
Seventh Revision of Sheet No. 91-11
Sixth Revision of Sheet No. 91-12
Sixth Revision of Sheet No. 91-13
Sixth Revision of Sheet No. 91-14
Sixth Revision of Sheet No. 91-15
Ninth Revision of Sheet No. 92-1
Fourth Revision of Sheet No. 95-3
Seventh Revision of Sheet No. 95-5
Seventh Revision of Sheet No. 123-1
Sixth Revision of Sheet No. 123-2
Eleventh Revision of Sheet No. 125-2
Eighth Revision of Sheet No. 126-1
Sixth Revision of Sheet No. 126-3
Seventeenth Revision of Sheet No. 128-1
Sixteenth Revision of Sheet No. 128-2
Twentieth Revision of Sheet No. 129-3
Seventh Revision of Sheet No. 485-3
Fourth Revision of Sheet No. 485-4
Eleventh Revision of Sheet No. 489-3
Sixth Revision of Sheet No. 489-4
Second Revision of Sheet No. 490-2
Second Revision of Sheet No. 490-3
Second Revision of Sheet No. 491-6
Second Revision of Sheet No. 491-7
Third Revision of Sheet No. 491-8
Second Revision of Sheet No. 491-9
Second Revision of Sheet No. 491-10
Second Revision of Sheet No. 491-11
Second Revision of Sheet No. 491-12
Second Revision of Sheet No. 491-13
Second Revision of Sheet No. 491-14
Second Revision of Sheet No. 492-1
Second Revision of Sheet No. 492-2
Second Revision of Sheet No. 495-3
Second Revision of Sheet No. 495-4
Third Revision of Sheet No. 495-5
Third Revision of Sheet No. 495-8
Seventh Revision of Sheet No. 515-1
Seventh Revision of Sheet No. 515-2
Sixth Revision of Sheet No. 515-3
Fifth Revision of Sheet No. 515-4
Second Revision of Sheet No. 515-5
Sixth Revision of Sheet No. 532-1
Seventh Revision of Sheet No. 538-1
Seventh Revision of Sheet No. 549-1
Tenth Revision of Sheet No. 575-1
First Revision of Sheet No. 575-6
Tenth Revision of Sheet No. 576R-1
Eighth Revision of Sheet No. 583-1
Fifth Revision of Sheet No. 585-1
Tenth Revision of Sheet No. 589-1
Second Revision of Sheet No. 590-1
Twelfth Revision of Sheet No. 591-6
Thirteenth Revision of Sheet No. 591-7
Eighth Revision of Sheet No. 591-8
Seventh Revision of Sheet No. 591-9
Seventh Revision of Sheet No. 591-10
Fifth Revision of Sheet No. 591-11
Fifth Revision of Sheet No. 591-12
Sixth Revision of Sheet No. 591-13
Seventh Revision of Sheet No. 592-1
Fifth Revision of Sheet No. 595-3
Fourth Revision of Sheet No. 595-6
Second Revision of Sheet No. 750-1
Second Revision of Sheet No. 750-2
Second Revision of Sheet No. 750-3

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	$11.00		(I) (C)
Transmission and Related Services Charge	0.243	¢ per kWh	(R)
Distribution Charge	4.100	¢ per kWh	(I)
Energy Charge Options			
Standard Service			
First 1,000 kWh	6.524	¢ per kWh	
Over 1,000 kWh	7.246	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio (Whole Premises or Electric Vehicle (EV) TOU) (Enrollment is necessary)			
On-Peak Period	12.626	¢ per kWh	
Mid-Peak Period	7.246	¢ per kWh	
Off-Peak Period	4.210	¢ per kWh	(I)
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	0.122	¢ per kWh	(R)
Distribution Charge	5.252	¢ per kWh	(I)
Cost of Service Energy Charge	5.366	¢ per kWh	(I)

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate (1) Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$ 12.67 (2)	(R)
	400	21,000	147	21.80 (2)	(I)
	1,000	55,000	374	46.58 (2)	(I)
HPS	70	6,300	30	8.87 (2)	(R)
	100	9,500	43	10.24	(R)
	150	16,000	62	12.38	(I)
	200	22,000	79	14.47	
	250	29,000	102	16.89	
	310	37,000	124	19.66 (2)	
	400	50,000	163	23.60	(I)
Flood, HPS	100	9,500	43	10.11 (2)	(R)
	200	22,000	79	14.88 (2)	
	250	29,000	102	17.31	(R)
	400	50,000	163	23.87	(I)
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	10.30	(R)
	100	9,500	43	11.40	
	150	16,500	62	13.64	
Special Acorn Type, HPS	100	9,500	43	13.81	
HADCO Victorian, HPS	150	16,500	62	15.89	
	200	22,000	79	18.47	
	250	29,000	102	20.94	
Early American Post-Top, HPS Black	100	9,500	43	10.66	(R)

(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	$ 12.66	(R)
	175	12,000	71	13.89	|
Flood, Metal Halide	350	30,000	139	21.54	(R)
	400	40,000	156	23.29	(I)
Flood, HPS	750	105,000	285	40.34	(I)
HADCO Independence, HPS	100	9,500	43	14.62	(R)
	150	16,000	62	15.66	|
HADCO Capitol Acorn, HPS	100	9,500	43	17.12	|
	150	16,000	62	18.46	|
	200	22,000	79	21.81	|
	250	29,000	102	22.75	(R)
HADCO Techtra, HPS	100	9,500	43	23.37	(I)
	150	16,000	62	24.80	|
	250	29,000	102	29.02	(I)
HADCO Westbrooke, HPS	70	6,300	30	15.25	(R)
	100	9,500	43	16.07	|
	150	16,000	62	18.12	|
	200	22,000	79	20.13	|
	250	29,000	102	22.79	|
KIM Archetype, HPS	250	29,000	102	24.15	(R)
	400	50,000	163	28.20	(I)
Holophane Mongoose, HPS	150	16,000	62	16.23	(R)
	250	29,000	102	19.91	(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	$ 14.27	(R)
	70	4,332	24	16.40	
Cobrahead Equivalent					
LED	37	2,530	13	4.68	
	50	3,162	17	5.11	
	52	3,757	18	5.55	
	67	5,050	23	6.32	
	106	7,444	36	8.42	
Westbrooke LED (Non-Flare)	53	5,079	18	18.16	
	69	6,661	24	18.22	
	85	8,153	29	18.96	
	136	12,687	46	23.87	
	206	18,159	70	26.37	
Westbrooke LED (Flare)	53	5,079	18	20.31	
	69	6,661	24	20.96	
	85	8,153	29	20.42	
	136	12,687	46	24.96	
	206	18,159	70	27.54	
CREE XSP LED	25	2,529	9	3.50	
	42	3,819	14	4.12	
	48	4,373	16	4.78	
	56	5,863	19	5.57	
	91	8,747	31	6.86	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Rates for Area Light Poles[1]			
Wood, Standard	35 or less	$ 5.59	(R)
	40 to 55	7.31	
Wood, Painted for Underground	35 or less	5.59 [2]	
Wood, Curved Laminated	30 or less	6.93 [2]	
Aluminum, Regular	16	6.67	
	25	11.07	
	30	11.96	
	35	14.30	
Aluminum, Fluted Ornamental	14	9.76	
Aluminum Davit	25	10.23	
	30	10.99	
	35	12.02	
	40	16.30	
Aluminum Double Davit	30	16.22	
Aluminum, HADCO, Fluted Ornamental	16	9.98	
Aluminum, HADCO, Non-fluted Techtra Ornamental	18	19.21	
Aluminum, HADCO, Fluted Westbrooke	18	19.26	
Aluminum, HADCO, Non-Fluted Westbrooke	18	20.41	
Concrete Ameron Post-Top	25	19.16	(R)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Rates for Area Light Poles[(1)]			
Fiberglass Fluted Ornamental; Black	14	$ 11.81	(R)
Fiberglass, Regular			
Black	20	4.91	
Gray or Bronze	30	8.35	
Other Colors (as available)	35	7.19	
Fiberglass, Anchor Base Gray	35	13.11	
Fiberglass, Direct Bury with Shroud	18	7.92	(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.

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	$16.00		(I)
Three Phase Service	$22.00		(I)
Transmission and Related Services Charge	0.210	¢ per kWh	(R)
Distribution Charge			
First 5,000 kWh	4.049	¢ per kWh	(I)
Over 5,000 kWh	0.999	¢ per kWh	(R)
Energy Charge Options			
Standard Service	6.230	¢ per kWh	(I)
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.962	¢ per kWh	(I)
Mid-Peak Period	6.230	¢ per kWh	(I)
Off-Peak Period	3.656	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

DAILY PRICE

The Daily Price, applicable with Direct Access Service, is available to those Customers who were served under Schedule 532 and subsequently returned to this schedule before meeting the minimum term requirement of Schedule 532. The Customer will be charged the Daily Price charge of this schedule until the term requirement of Schedule 532 is met.

The Daily Price will consist of:

- the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index)
- plus 0.305 ¢ 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.

PLUG-IN ELECTRIC VEHICLE (EV) TOU OPTION

A small Nonresidential Customer wishing to charge EV's may do so either as part of an integrated service (Standard service or TOU service) or as a separately metered service billed under the TOU option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule. Renewable Portfolio Options are also available under this EV option.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B (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 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	0.210	¢ per kWh	(C) (I)
Distribution Charge	7.526	¢ per kWh	
Energy Charge*			
On-Peak Period	7.183	¢ per kWh	
Off-Peak Period	6.183	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** On-peak Period is Monday-Friday, 7:00 a.m. to 8:00 p.m. off-peak Period is Monday-Friday, 8:00 p.m. to 7:00 a.m.; and all day Saturday and Sunday.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 38 (Continued)

DIRECT ACCESS DEFAULT SERVICE

A Customer returning to Schedule 38 service before completing the term of service specified in Schedule 538, must be billed at the Daily Price for the remainder of the term. This provision does not eliminate the requirement to receive service on Schedule 81 when notice is insufficient. The Daily Price under this schedule is as follows:

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(I)**

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**	$44.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.210	¢ per kWh	(R)
Distribution Charge			
First 50 kWh per kW of Demand***	7.976	¢ per kWh	(I)
Over 50 kWh per kW of Demand	6.976	¢ per kWh	(I)
Energy Charge	6.230	¢ 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**	$50.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.210	¢ per kWh	(R)
Distribution Charge			
First 50 kWh per kW of Demand***	7.132	¢ per kWh	(I)
Over 50 kWh per kW of Demand	6.132	¢ per kWh	(I)
Energy Charge	6.731	¢ 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	$2,670.00	$1,620.00	$3,090.00	(R)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.79	$0.77	$0.76	(R)
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$0.99	$0.96	$0.96	(R)
Over 4,000 kW	$0.99	$0.96	$0.96	(R)
per kW of monthly On-Peak Demand	$2.38	$2.32	$1.21	(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	0.083 ¢	0.080 ¢	0.077 ¢	(I)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable.

Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Powerdex Mid-Columbia Hourly Firm Electricity Price Index (Powerdex-Mid-C Hourly Firm Index) plus 0.305¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, (I)
plus losses.

SCHEDULE 75 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Customer will not use Electricity sold by the Company to directly or indirectly make or continue a delivery of Electricity to another Customer or wholesale power purchaser.

7. A Customer's failure to inform the Company of the use of on-site generation will not relieve the Customer of responsibility for the charges and requirements under this schedule.

8. The Customer's Baseline Demand may be increased or decreased as requested by the Customer for planned, long-term load changes including changes resulting from the addition of long-term energy efficiency measures, load shedding, the addition or removal of equipment or the permanent removal of generating capacity from the Customer location. Such changes will be effective upon verification of the change by the Company. "Long-term" or "permanent" mean changes that are implemented with the purpose of being in place indefinitely. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the actual Customer generation. (N) (N)

9. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Customer provides the following notice:
   a) for a change to Baseline Demand that within a one calendar year period does not exceed 5 MW, the Customer may make one such request per calendar year and will provide at least 6 months written notice;

   b) for a change in Baseline Demand that is greater than 5 MW, Customer must provide at least 13 months written notice to the Company with such change effective on January 1 of the applicable year. Any subsequent notice by the Customer under this special condition must be made consistent with these notice requirements.

10. If the Customer's Baseline Demand is increased, any Energy used above the initial Baseline Demand, and below the revised Baseline Demand will be priced at the Daily Price Option contained in Schedule 89 unless the Customer has given the required notice to change the applicable Schedule 89 Energy Charge Option.

11. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council guidelines.

12. If the Customer is receiving service under this schedule and Schedule 76R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 76R Special Conditions.

13. A Customer may not change service options until it has satisfied any Baseline Energy term provisions as established in Schedule 89.

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:*

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Transmission and Related Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.031	$0.030	$0.030	
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.093	$0.090	$0.047	(I)
Transaction Fee per Energy Needs Forecast (ENF)	$50.00	$50.00	$50.00	
Energy Charge* per kWh of ERP	See below for ERP Pricing			

* See Schedule 100 for applicable adjustments.
** Peak hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours (also called light load hours "LLH") are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ENF Options for ERP (Continued)

The Daily ENF pre-scheduling protocols will conform to the standard practices, applicable definitions, requirements and schedules of the WECC. Pre-Schedule Day means the trading day immediately preceding the day of delivery consistent with WECC practices for Saturday, Sunday, Monday or holiday deliveries.

ERP Pricing

The following ERP Energy Charges are applied to the applicable hourly ENF and summed for the hours for the monthly billing:

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.305¢ per kWh for wheeling, plus (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 0.305¢ 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 0.305¢ 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 0.305¢ 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 0.305¢ 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 0.305¢ 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 0.305¢ per kWh for wheeling, **(I)** plus losses.
The Imbalance Settlement Amount may be a credit or charge in any hour.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

In all territory served by the Company. The Company may restrict Customer loads returning to this schedule in accordance with Rule N Curtailment Plan and Rule C (Section 2).

APPLICABLE

To existing Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule.

MONTHLY RATE

All charges for Emergency Default Service except the energy charge will be billed at the Customer's applicable Standard Service rate schedule for five business days after the Customer's initial purchase of Emergency Default Service.

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh **(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	$0.79	(R)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.85	(I)
Over 30 kW	$2.75	|
per kW of monthly On-Peak Demand	$2.38	(I)
Energy Charge (per kWh)		(T)
On-Peak Period***	6.666 ¢	(R)
Off-Peak Period***	5.166 ¢	(R)
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.874 ¢	(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 83 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus (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:

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	Delivery Voltage Primary	
Basic Charge	$430.00	$460.00	(I)
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.79	$0.77	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.01	$2.94	(I)
Over 200 kW	$2.11	$2.04	|
per kW of monthly On-Peak Demand	$2.38	$2.32	(I)
Energy Charge (per kWh)			(T)
On-Peak Period***	6.497 ¢	6.387 ¢	(R)
Off-Peak Period***	4.997 ¢	4.887 ¢	(R)
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.120 ¢	0.116 ¢	(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 85 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 85 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate Schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

NON COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(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	$2,670.00	$1,620.00	$3,090.00	(R)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.79	$0.77	$0.76	(R)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$0.99	$0.96	$0.96	(R)
Over 4,000 kW	$0.99	$0.96	$0.96	(R)
per kW of monthly On-Peak Demand	$2.38	$2.32	$1.21	(I)
Energy Charge (per kWh)				(T)
On-Peak Period***	6.409 ¢	6.304 ¢	6.225 ¢	(I)
Off-Peak Period***	4.909 ¢	4.804 ¢	4.725 ¢	(I)
See below for Daily Pricing Option description.				
System Usage Charge				
per kWh	0.083 ¢	0.080 ¢	0.077 ¢	(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 0.305¢ 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	$25,000.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.77	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$0.97	(R)
Over 4,000 kW	$0.97	(R)
per kW of monthly On-Peak Demand	$2.32	(I)
Energy Charge (per kWh)		(T)
On-Peak Period***	6.027 ¢	(I)
Off-Peak Period***	4.527 ¢	(I)
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.067 ¢	

* 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 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(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 90 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	0.122 ¢ per kWh	(R)
Distribution Charge	5.252 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.366 ¢ per kWh	(I)

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ 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	Option B	
Cobrahead Power Doors **	70	6,300	30	*	$ 1.33	(I)
	100	9,500	43	*	1.32	(R)
	150	16,000	62	*	1.33	
	200	22,000	79	*	1.37	
	250	29,000	102	*	1.35	
	400	50,000	163	*	1.39	(R)
Cobrahead	70	6,300	30	$ 4.70	1.57	(R)(I)
	100	9,500	43	4.68	1.55	
	150	16,000	62	4.78	1.57	(I)
	200	22,000	79	5.41	1.62	(R)
	250	29,000	102	5.35	1.61	
	400	50,000	163	5.51	1.62	
Flood	250	29,000	102	5.78	1.66	
	400	50,000	163	5.78	1.66	
Early American Post-Top	100	9,500	43	5.10	1.61	(R)
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	6.14	1.76	(I)
	100	9,500	43	5.84	1.71	(R)
	150	16,000	62	6.04	1.74	(R)(R)

* Not offered.
** Service is only available to Customers with total power door luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black	20	$ 4.91	$ 0.15	(R)(I)
Fiberglass, Bronze	30	7.74	0.23	
Fiberglass, Gray	30	8.35	0.25	
Wood, Standard	30 to 35	5.59	0.17	
Wood, Standard	40 to 55	7.31	0.22	(R)(I)

Portland General Electric Company | Seventh Revision of Sheet No. 91-10
P.U.C. Oregon No. E-18 | Canceling Sixth Revision of Sheet No. 91-10

SCHEDULE 91 (Continued)

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	$ 8.61	$ 2.05	(R)(R)
HADCO Victorian, HPS	150	16,000	62	8.65	2.06	
	200	22,000	79	9.41	2.17	
	250	29,000	102	9.41	2.17	
HADCO Capitol Acorn, HPS	100	9,500	43	11.92	2.49	
	150	16,000	62	11.22	2.41	(R)
	200	22,000	79	12.75	2.62	(I)
	250	29,000	102	11.22	2.41	(R)
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	9.42	2.14	(I)
	150	16,000	62	8.42	2.01	(R)(R)
HADCO Techtra, HPS	100	9,500	43	18.17	3.32	(I) (I)
	150	16,000	62	17.56	3.24	(R)
	250	29,000	102	17.49	3.24	(I)
HADCO Westbrooke, HPS	70	6,300	30	11.45	2.43	(R) (I)
	100	9,500	43	10.87	2.34	(R)
	150	16,000	62	10.88	2.35	
	200	22,000	79	11.07	2.38	
	250	29,000	102	11.26	2.41	(R)(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						
Cobrahead, Metal Halide	150	10,000	60	$ 5.28	$ 1.87	(R)(R)
Flood, Metal Halide	350	30,000	139	6.03	1.94	(R)
Flood, HPS	750	105,000	285	9.14	2.88	(I)
Holophane Mongoose, HPS	150	16,000	62	8.98	2.10	(R)
	250	29,000	102	8.38	2.01	(R)(R)
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	
Ornamental Acorn	55	2,800	21	*	*	
Ornamental Acorn Twin	55	5,600	42	*	*	
Composite, Twin	140	6,815	54	*	*	
	175	9,815	66	*	*	

* Not offered.
** Rates are based on current kWh energy charges.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 6.67	$ 0.20	(R)(I)
	25	11.07	0.33	
	30	11.96	0.36	
	35	14.30	0.43	
Aluminum Davit	25	11.05	0.33	
	30	10.99	0.33	
	35	12.02	0.36	
	40	16.30	0.49	
Aluminum Double Davit	30	16.22	0.48	(R)(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, HADCO, Fluted Victorian Ornamental	14	$ 9.76	$ 0.29	(R)(I)
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	19.21	0.57	
Aluminum, HADCO, Fluted Ornamental	16	9.98	0.30	
Aluminum, HADCO, Non-Fluted Ornamental	16	20.41	0.61	
Aluminum, HADCO, Fluted Westbrooke	18	19.26	0.57	
Aluminum, HADCO, Non-Fluted Westbrooke	18	20.41	0.61	
Aluminum, Painted Ornamental	35	32.80	0.98	
Concrete. Decorative Ameron	20	19.16	0.57	
Concrete, Ameron Post-Top	25	19.16	0.57	
Fiberglass, HADCO, Fluted Ornamental Black	14	11.81	0.35	
Fiberglass, Smooth	18	4.90	0.15	
Fiberglass, Regular				
color may vary	22	4.38	0.13	
	35	7.19	0.21	
Fiberglass, Anchor Base, Gray	35	13.11	0.39	
Fiberglass, Direct Bury with Shroud	18	7.92	0.24	(R)(I)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	$ 4.64	$ 1.51	(R)(I)
	250	10,000	94	*	*	
	400	21,000	147	5.43	1.64	(I)
	1,000	55,000	374	5.83	1.94	
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	5.78	1.65	
Mercury Vapor	175	7,000	66	5.74	1.61	(R)(I)

* 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	*	$ 1.99	
	150	16,000	62	*	2.01	
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	1.26	(I)
	400	40,000	156	*	1.26	
Cobrahead, Metal Halide	175	12,000	71	$ 5.32	1.72	(R)
Flood, Metal Halide	400	40,000	156	5.96	1.88	(R)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	1.57	
100/150 Watt Ballast	100	9,500	43	*	1.57	
100/150 Watt Ballast	150	16,000	62	*	1.59	(I)
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.73	(R)
	165	12,000	60	*	0.88	
HADCO Techtra, QL	165	12,000	60	18.94	1.16	(R)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	2.53	
KIM Archetype, HPS	250	29,000	102	*	2.58	(R)
	400	50,000	163	*	2.24	(I)
Special Acorn-Type, HPS	70	6,300	30	8.63	2.07	(R)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	
Special Acrylic Sphere						
Mercury Vapor	400	21,000	147	*	*	

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Early American Post-Top, HPS						
Black	70	6,300	30	$ 5.03	$ 1.54	(R)(I)
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	5.04	1.55	(R)(I)
Flood, HPS	70	6,300	30	4.58	1.45	
	100	9,500	43	4.54	1.56	
	200	22,000	79	5.82	1.70	(I)
Cobrahead, HPS						
Power Door	310	37,000	124	5.75	2.01	(R)(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	$ 6.67	*	(R)
Bronze Alloy GardCo	12	*	$ 0.18	(I)
Concrete, Ornamental	35 or less	11.07	0.33	(R)
Steel, Painted Regular **	25	11.07	0.33	
Steel, Painted Regular **	30	11.96	0.36	(R)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.33	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.33	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.36	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.36	
Wood, Laminated without Mast Arm	20	4.91	0.15	(R)(I)
Wood, Laminated Street Light Only	20	4.91	*	
Wood, Curved Laminated	30	7.74	0.23	(I)
Wood, Painted Underground	35	5.59	0.17	(I)
Wood, Painted Street Light Only	35	5.59	*	(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	0.161	¢ per kWh	(R)
Distribution Charge	2.342	¢ per kWh	(I)
Energy Charge	5.484	¢ 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	0.122 ¢ per kWh	(R)
Distribution Charge	5.252 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.366 ¢ per kWh	(I)

NON-COST OF SERVICE OPTION

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. (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]
	$133.00 per hour	$188.00 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	$ 2.95	(R)
Cobrahead Equivalent	50	3,162	17	2.95	
Cobrahead Equivalent	52	3,757	18	3.28	
Cobrahead Equivalent	67	5,050	23	3.66	
Cobrahead Equivalent	106	7,444	36	4.36	(R)

RATES FOR DECORATIVE LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$ 11.43	(R)
	70	4,332	24	13.24	
Westbrooke (Non-Flared)	53	5,079	18	15.65	
LED	69	6,661	24	15.06	
	85	8,153	29	15.27	
	136	12,687	46	18.34	
	206	18,159	70	18.27	
Westbrooke (Flared)	53	5,079	18	17.79	
LED	69	6,661	24	17.79	
	85	8,153	29	16.73	
	136	12,687	46	19.43	
	206	18,159	70	19.43	(R)

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 7.368 cents/kWh for Schedule 7 (I)
and 6.727 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 $62.52 per month for Schedule 7 and $99.23 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 70% 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 $43.76. (R)

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 5.125 (I)
cents per kWh.

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 1.0337. (I)

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 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 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 1.0337 (I)
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.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0337 to account for franchise fees, uncollectables, and OPUC fees. **(I)**

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 85, 89, 90, 91 or 95 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 590, 591, 592 and 595. This Schedule is not applicable to Customers served on Schedules 485, 489, 490, 491, 492 and 495.

SHORT-TERM TRANSITION ADJUSTMENT

The Short-Term Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service in 2015, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2016: **(C)** **(C)**

Schedule		Annual ¢ per kWh [1]	
32		2.647	(I)
38		3.079	
75	Secondary	2.260 [2]	
	Primary	2.219 [2]	
	Subtransmission	2.220 [2]	(I)
83		2.529	(R)
85	Secondary	2.390	
	Primary	2.319	(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	2.260	(I)
	Primary	2.219	|
	Subtransmission	2.220	(I)
90		1.921	(R)
91		2.011	(I)
95		2.011	|
515		2.011	|
532		2.647	|
538		3.079	(I)
549		3.185	(R)
575	Secondary	2.260 (2)	(I)
	Primary	2.219 (2)	|
	Subtransmission	2.220 (2)	(I)
583		2.529	(R)
585	Secondary	2.390	|
	Primary	2.319	(R)
589	Secondary	2.260	(I)
	Primary	2.219	|
	Subtransmission	2.220	|
590		1.921	|
591		2.011	(I)
592		1.961	(R)
595		2.011	(I)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT REVISIONS

The Annual Short-Term Transition Adjustment rate will be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. Indicative, non-binding estimates for the Annual Short-Term Transition Adjustment and Cost-of-Service Energy Prices will be posted by the Company by September 1 and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

SCHEDULE 129 (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

For Enrollment Period M (2014), the Transition Cost Adjustment will be:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2015	1.712	1.704	1.443	1.415	1.383	1.381	1.311	(I)
2016	1.788	1.778	1.524	1.495	1.462	1.453	1.423	
2017	1.788	1.778	1.524	1.495	1.462	1.453	1.423	
2018	1.788	1.778	1.524	1.495	1.462	1.453	1.423	
2019	1.788	1.778	1.524	1.495	1.462	1.453	1.423	
After 2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(I)

Three Year Opt-Out

This option was not available during Enrollment Periods A and B.

For Enrollment Period C (2004), No Longer Applicable

For Enrollment Period D (2005), No Longer Applicable

For Enrollment Period E (2006), No Longer Applicable

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	$430.00	$460.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.01	$2.94	(I)
Over 200 kW	$2.11	$2.04	|
per kW of monthly On-Peak Demand	$2.38	$2.32	(I)
System Usage Charge			
per kWh	(0.026) ¢	(0.027) ¢	(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 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 $1.796 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	$2,670.00	$1,620.00	$3,090.00	(R)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$0.99	$0.96	$0.96	(R)
Over 4,000 kW	$0.99	$0.96	$0.96	(R)
per kW of monthly On-Peak Demand	$2.38	$2.32	$1.21	(I)
System Usage Charge				
per kWh	(0.058) ¢	(0.058) ¢	(0.059) ¢	(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 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 $1.796 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	$25,000.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$0.97	(R)
Over 4,000 kW	$0.97	(R)
per kW of monthly On-Peak Demand	$2.32	(I)
System Usage Charge		
per kWh	(0.077) ¢	(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 $1.796 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	5.109 ¢ 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 $1.796 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)
	$133.00 per hour	$188.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead Power Doors **							
	70	6,300	30	*	$ 2.86	$ 1.53	(I)
	100	9,500	43	*	3.52	2.20	
	150	16,000	62	*	4.50	3.17	
	200	22,000	79	*	5.41	4.04	
	250	29,000	102	*	6.56	5.21	
	400	50,000	163	*	9.72	8.33	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.23	3.10	1.53	(R)
	100	9,500	43	6.88	3.75	2.20	(R)
	150	16,000	62	7.95	4.74	3.17	(I)
	200	22,000	79	9.45	5.66	4.04	
	250	29,000	102	10.56	6.82	5.21	
	400	50,000	163	13.84	9.95	8.33	
Flood	250	29,000	102	10.99	6.87	5.21	
	400	50,000	163	14.11	9.99	8.33	(I)
Early American Post-Top	100	9,500	43	7.30	3.81	2.20	(R)
Shoebox (Bronze color, flat	70	6,300	30	7.67	3.29	1.53	
Lens, or drop lens, multi-volt)	100	9,500	43	8.04	3.91	2.20	(R)
	150	16,000	62	9.21	4.91	3.17	(R)(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 491 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black	20	$ 4.91	$ 0.15	(R)(I)
Fiberglass, Bronze	30	7.74	0.23	
Fiberglass, Gray	30	8.35	0.25	
Wood, Standard	30 to 35	5.59	0.17	
Wood, Standard	40 to 55	7.31	0.22	(R)(I)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Acorn-Types							
HPS	100	9,500	43	$ 10.81	$ 4.25	$ 2.20	(R)(I)
HADCO Victorian, HPS	150	16,000	62	11.82	5.23	3.17	
	200	22,000	79	13.45	6.21	4.04	
	250	29,000	102	14.62	7.38	5.21	
HADCO Capitol Acorn, HPS	100	9,500	43	14.12	4.69	2.20	
	150	16,000	62	14.39	5.58	3.17	
	200	22,000	79	16.79	6.66	4.04	
	250	29,000	102	16.43	7.62	5.21	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	11.62	4.34	2.20	
	150	16,000	62	11.59	5.18	3.17	(R)
HADCO Techtra, HPS	100	9,500	43	20.37	5.52	2.20	(I)
	150	16,000	62	20.73	6.41	3.17	
	250	29,000	102	22.70	8.45	5.21	(I)
HADCO Westbrooke, HPS	70	6,300	30	12.98	3.96	1.53	(R)
	100	9,500	43	13.07	4.54	2.20	
	150	16,000	62	14.05	5.52	3.17	
	200	22,000	79	15.11	6.42	4.04	
	250	29,000	102	16.47	7.62	5.21	(R)(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	
Special Types							
Cobrahead, Metal Halide	150	10,000	60	$ 8.35	$ 4.94	$ 3.07	(I)
Flood, Metal Halide	350	30,000	139	13.13	9.04	7.10	(R)
Flood, HPS	750	105,000	285	23.70	17.44	14.56	(I)
Holophane Mongoose, HPS	150	16,000	62	12.15	5.27	3.17	(R)
	250	29,000	102	13.59	7.22	5.21	(R)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	3.27	
Ornamental Acorn	55	2,800	21	*	*	1.07	
Ornamental Acorn Twin	55	5,600	42	*	*	2.15	
Composite, Twin	140	6,815	54	*	*	2.76	
	175	9,815	66	*	*	3.37	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 6.67	$ 0.20	(R)(I)
	25	11.07	0.33	
	30	11.96	0.36	
	35	14.30	0.43	
Aluminum Davit	25	11.05	0.33	
	30	10.99	0.33	
	35	12.02	0.36	
	40	16.30	0.49	
Aluminum Double Davit	30	16.22	0.48	
Aluminum, HADCO, Fluted Victorian Ornamental	14	9.76	0.29	(R)(I)

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	$ 19.21	$ 0.57	(R)(I)
Aluminum, HADCO, Fluted Ornamental	16	9.98	0.30	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	20.41	0.61	
Aluminum, HADCO, Fluted Westbrooke	18	19.26	0.57	
Aluminum, HADCO, Non-Fluted, Westbrooke	18	20.41	0.61	
Aluminum, Painted Ornamental	35	32.80	0.98	
Concrete, Decorative Ameron	20	19.16	0.57	
Concrete, Ameron Post-Top	25	19.16	0.57	
Fiberglass, HADCO, Fluted Ornamental Black	14	11.81	0.35	
Fiberglass, Smooth	18	4.90	0.15	
Fiberglass, Regular,				
color may vary	22	4.38	0.13	
color may vary	35	7.19	0.21	
Fiberglass, Anchor Base, Gray	35	13.11	0.39	
Fiberglass, Direct Bury with Shroud	18	7.92	0.24	(R)(I)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$ 1.99	(I)
	175	7,000	66	$ 8.01	$ 4.88	3.37	
	250	10,000	94	*	*	4.80	
	400	21,000	147	12.94	9.15	7.51	
	1,000	55,000	374	24.94	21.05	19.11	(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	$ 7.31	$ 3.18	$ 1.53	(R)(I)
Mercury Vapor	175	7,000	66	9.11	4.98	3.37	(R)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	3.07	
	70	6,300	30	*	*	1.53	
	100	9,500	43	*	4.19	2.20	
	150	16,000	62	*	5.18	3.17	
	250	29,000	102	*	*	5.21	
	400	50,000	163	*	*	8.33	
Metal Halide	250	20,500	99	*	6.32	5.06	
	400	40,000	156	*	9.23	7.97	
Cobrahead, Metal Halide	175	12,000	71	8.95	5.35	3.63	(R)
Flood, Metal Halide	400	40,000	156	13.93	9.85	7.97	(I)
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.77	2.20	
100/150 Watt Ballast	100	9,500	43	*	3.77	2.20	
100/150 Watt Ballast	150	16,000	62	*	4.76	3.17	
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.70	3.17	
KIM Archetype, HPS	250	29,000	102	*	7.79	5.21	
	400	50,000	163	*	10.57	8.33	(I)

* Not offered

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$ 10.16	$ 3.60	$ 1.53	(R)(I)
Special GardCo Bronze Alloy							
HPS	70	6,300	30	*	*	1.53	
Mercury Vapor	175	7,000	66	*	*	3.37	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	7.51	
Early American Post-Top, HPS							
Black	70	6,300	30	6.56	3.07	1.53	(R)
Rectangle Type	200	22,000	79	*	*	4.04	
Incandescent	92	1,000	31	*	*	1.58	
	182	2,500	62	*	*	3.17	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	8.41	4.92	3.37	(R)
Flood, HPS	70	6,300	30	6.11	2.98	1.53	
	100	9,500	43	6.74	3.76	2.20	
	200	22,000	79	9.86	5.74	4.04	(R)
Cobrahead, HPS							
Power Door	310	37,000	124	12.09	8.35	6.34	(I)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.20	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	4.39	
Compact Fluorescent	28	N/A	12	*	*	0.61	(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	$ 6.67	*	(R)
Bronze Alloy GardCo	12	*	$ 0.18	(I)
Concrete, Ornamental	35 or less	11.07	0.33	(R)
Steel, Painted Regular **	25	11.07	0.33	
Steel, Painted Regular **	30	11.96	0.36	(R)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.33	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.33	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.36	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.36	
Wood, Laminated without Mast Arm	20	4.91	0.15	(R)
Wood, Laminated Street Light Only	20	4.91	*	
Wood, Curved Laminated	30	7.74	0.23	
Wood, Painted Underground	35	5.59	0.17	(I)
Wood, Painted Street Light Only	35	5.59	*	(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	*	$ 2.36	$ 1.63	(I)
	165	12,000	60	*	3.95	3.07	
	165	12,000	60	$ 22.01	4.23	3.07	(R)(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	2.195 ¢ 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 $1.796 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 5.109 ¢ 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 $1.796 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
	$133.00 per hour	$188.00 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	$ 3.61	(R)
LED	50	3,162	17	3.82	
LED	52	3,757	18	4.20	
LED	67	5,050	23	4.84	
LED	106	7,444	36	6.20	(R)

Portland General Electric Company | Third Revision of Sheet No. 495-8
P.U.C. Oregon No. E-18 | Canceling Second Revision of Sheet No. 495-8

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	$ 12.50	(R)
	70	4,332	24	14.47	
Westbrooke (Non-Flared)	53	5,079	18	16.57	
LED	69	6,661	24	16.29	
	85	8,153	29	16.75	
	136	12,687	46	20.69	
	206	18,159	70	21.85	
Westbrooke (Flared)	53	5,079	18	18.71	
LED	69	6,661	24	19.02	
	85	8,153	29	18.21	
	136	12,687	46	21.78	
	206	18,159	70	23.01	(R)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

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	$ 8.95 [2]	(R)
	400	21,000	147	13.52 [2]	(I)
	1,000	55,000	374	25.52 [2]	(I)
HPS	70	6,300	30	7.18 [2]	(R)
	100	9,500	43	7.82	(R)
	150	16,000	62	8.89	(I)
	200	22,000	79	10.03	|
	250	29,000	102	11.15	|
	310	37,000	124	12.68 [2]	|
	400	50,000	163	14.42	(I)
Flood , HPS	100	9,500	43	7.69 [2]	(R)
	200	22,000	79	10.44 [2]	|
	250	29,000	102	11.57	(R)
	400	50,000	163	14.69	(I)
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	8.61	(R)
	100	9,500	43	8.98	|
	150	16,500	62	10.15	(R)

(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	$ 11.39	(R)
HADCO Victorian, HPS	150	16,500	62	12.40	
	200	22,000	79	14.03	
	250	29,000	102	15.20	
Early American Post-Top, HPS, Black	100	9,500	43	8.24	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	9.29	
Cobrahead, Metal Halide	175	12,000	71	9.89	
Flood, Metal Halide	350	30,000	139	13.71	(R)
Flood, Metal Halide	400	40,000	156	14.51	(I)
Flood, HPS	750	105,000	285	24.29	(I)
HADCO Independence, HPS	100	9,500	43	12.20	(R)
	150	16,000	62	12.17	
HADCO Capitol Acorn, HPS	100	9,500	43	14.70	
	150	16,000	62	14.97	
	200	22,000	79	17.37	
	250	29,000	102	17.01	(R)
HADCO Techtra, HPS	100	9,500	43	20.95	(I)
	150	16,000	62	21.31	
	250	29,000	102	23.28	(I)
HADCO Westbrooke, HPS	70	6,300	30	13.56	(R)
	100	9,500	43	13.65	
	150	16,000	62	14.63	
	200	22,000	79	15.69	
	250	29,000	102	17.05	
KIM Archetype, HPS	250	29,000	102	18.41	(R)
	400	50,000	163	19.02	(I)
Holophane Mongoose, HPS	150	16,000	62	12.74	(R)
	250	29,000	102	14.17	(R)

(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	$ 13.08	(R)
	70	4,332	24	15.05	
Cobrahead					
LED	37	2,530	13	3.94	
	50	3,162	17	4.15	
	52	3,757	18	4.54	
	67	5,050	23	5.03	
	106	7,444	36	6.39	
Westbrooke LED (Non-Flare)	53	5,079	18	17.15	
	69	6,661	24	16.87	
	85	8,153	29	17.33	
	136	12,687	46	21.28	
	206	18,159	70	22.43	
Westbrooke LED (Flare)	53	5,079	18	19.30	
	69	6,661	24	19.61	
	85	8,153	29	18.79	
	136	12,687	46	22.37	
	206	18,159	70	23.60	
CREE XSP LED	25	2,529	9	2.99	
	42	3,819	14	3.34	
	48	4,373	16	3.88	
	56	5,863	19	4.50	
	91	8,747	31	5.11	(R)

(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	$ 5.59	(R)
	40 to 55	7.31	
Wood, Painted Underground	35 or less	5.59 [2]	
Wood, Curved laminated	30 or less	6.93 [2]	
Aluminum, Regular	16	6.67	
	25	11.07	
	30	11.96	
	35	14.30	
Aluminum, Fluted Ornamental	14	9.76	
Aluminum Davit	25	10.23	
	30	10.99	
	35	12.02	
	40	16.30	
Aluminum Double Davit	30	16.22	
Aluminum, HADCO, Fluted Ornamental	16	9.98	
Aluminum, HADCO, Non-fluted	18	19.21	(R)
Aluminum, HADCO, Fluted Westbrooke	18	19.26	(N)
Aluminum, HADCO, Non-Fluted Westbrooke	18	20.41	(N)
Concrete, Ameron Post-Top	25	19.16	(R)
Fiberglass Fluted Ornamental; Black	14	11.81	
Fiberglass, Regular			
Black,	20	4.91	
Gray or Bronze;	30	8.35	
Other Colors (as available)	35	7.19	
Fiberglass, Anchor Base Gray	35	13.11	
Fiberglass, Direct Bury with Shroud	18	7.92	(R)

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

(M)

SCHEDULE 515 (Concluded)

INSTALLATION CHARGE (M)

See Schedule 300 regarding the installation of conduit on wood poles. (M)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file to add the luminaire type to this rate schedule.

2. Maintenance of outdoor area lighting poles includes replacement of accidentally or deliberately damaged poles and luminaires. If damage occurs more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will pay for future installation or may mutually agree with the Company and pay to have the pole either completely removed or relocated.

3. If Company-owned area lighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned area lighting equipment or poles.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase	$16.00	(I)
Three Phase	$22.00	(I)
Distribution Charge		
First 5,000 kWh	3.882 ¢ per kWh	(I)
Over 5,000 kWh	0.832 ¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 538
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers who have chosen to receive service from an Electricity Service Supplier (ESS), and: 1) served at Secondary 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		(C)
Distribution Charge	7.369	¢ 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)*:

Basic Charge		
Summer Months**	$50.00	(I)
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	6.937 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	5.937 ¢ 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	$2,670.00	$1,620.00	$3,090.00	(R)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$0.99	$0.96	$0.96	(R)
Over 4,000 kW	$0.99	$0.96	$0.96	(R)
per kW of monthly On-Peak Demand**	$2.38	$2.32	$1.21	(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	(0.058) ¢	(0.058) ¢	(0.059) ¢	(R)

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.
*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 575 (Continued)

SPECIAL CONDITIONS (Continued)

4. If the Customer is served at Primary or Subtransmission Voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. If during a Billing Period, the Customer or its ESS is billed for Ancillary Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8) and Schedule 3, Regulation and Frequency Response Service will be credited to the Ancillary Services Charge under this schedule. The credit will be the actual OATT charges incurred but will not to exceed the Monthly Demand for the Schedule 575 monthly Ancillary Services Demand multiplied by the applicable OATT (OATT Schedules 3, 7 or 8) and such credit will not exceed the Ancillary Services Charge incurred under this schedule. No credit will be provided against any Energy Imbalance Service charges.

6. A Customer's failure to inform the Company of use of on-site generation will not relieve the Customer of responsibility for the charges and requirements under this schedule.

7. The Customer's Baseline Demand may be increased or decreased as requested by the Customer for planned, long-term load changes including changes resulting from the addition of long-term energy efficiency measures, load shedding, the addition or removal of equipment or the permanent removal of generating capacity from the Customer location. Such changes will be effective upon verification of the change by the Company. "Long-term" or "permanent" mean changes that are implemented with the purpose of being in place indefinitely. The Customer's Baseline Demand may be modified by the Company if the (N)
Company determines that the level does not reflect load adjusted for the actual Customer
generation. (N)

8. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Customer provides the following notice:

   a) for a change to Baseline Demand that within a one calendar year period does not exceed 5 MW, the Customer may make one such request per calendar year and will provide at least 6 months written notice;

   b) for a change in Baseline Demand that is greater than 5 MW, Customer must provide at least 13 months written notice to the Company with such change effective on January 1 of the applicable year. Any subsequent notice by the Customer under this special condition must be made consistent with these notice requirements.

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**	$0.093	$0.090	$0.047	(I)
Transaction Fee per Energy Needs Forecast (ENF) submission or revision	$50.00	$50.00	$50.00	

* See Schedule 100 for applicable adjustments.

** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per 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	$2.85	(I)
Over 30 kW	$2.75	
per kW of monthly On-Peak Demand	$2.38	
System Usage Charge		
per kWh	0.710 ¢	(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 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	$430.00	$460.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.01	$2.94	(I)
Over 200 kW	$2.11	$2.04	
per kW of monthly On-Peak Demand	$2.38	$2.32	
System Usage Charge			
per kWh	(0.026) ¢	(0.027) ¢	(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 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	$2,670.00	$1,620.00	$3,090.00	(R)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$0.99	$0.96	$0.96	(R)
Over 4,000 kW	$0.99	$0.96	$0.96	(R)
per kW of monthly on-peak Demand	$2.38	$2.32	$1.21	(I)
System Usage Charge				
per kWh	(0.058) ¢	(0.058) ¢	(0.059) ¢	(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 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)*:

Basic Charge	$25,000.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$0.97	(R)
Over 4,000 kW	$0.97	(R)
per kW of monthly on-peak Demand	$2.32	(I)
System Usage Charge		
per kWh	(0.077) ¢	(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	5.109 ¢ 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

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$133.00 per hour	$188.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead Power Doors **							
	70	6,300	30	*	$ 2.86	$ 1.53	(I)
	100	9,500	43	*	3.52	2.20	
	150	16,000	62	*	4.50	3.17	
	200	22,000	79	*	5.41	4.04	
	250	29,000	102	*	6.56	5.21	
	400	50,000	163	*	9.72	8.33	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.23	3.10	1.53	(R)
	100	9,500	43	6.88	3.75	2.20	(R)
	150	16,000	62	7.95	4.74	3.17	(I)
	200	22,000	79	9.45	5.66	4.04	
	250	29,000	102	10.56	6.82	5.21	
	400	50,000	163	13.84	9.95	8.33	(I)
Flood	250	29,000	102	10.99	6.87	5.21	(R)
	400	50,000	163	14.11	9.99	8.33	(I)
Early American Post-Top	100	9,500	43	7.30	3.81	2.20	(R)
Shoebox (Bronze color, flat	70	6,300	30	7.67	3.29	1.53	
Lens, or drop lens, multi-volt)	100	9,500	43	8.04	3.91	2.20	(R)
	150	16,000	62	9.21	4.91	3.17	(R)(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	20	$ 4.91	$ 0.15	(R)(I)
Fiberglass, Bronze	30	7.74	0.23	
Fiberglass, Gray	30	8.35	0.25	
Wood, Standard	30 to 35	5.59	0.17	
Wood, Standard	40 to 55	7.31	0.22	(R)(I)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Acorn-Types							
HPS	100	9,500	43	$ 10.81	$ 4.25	$ 2.20	(R)(I)
HADCO Victorian, HPS	150	16,000	62	11.82	5.23	3.17	
	200	22,000	79	13.45	6.21	4.04	
	250	29,000	102	14.62	7.38	5.21	
HADCO Capitol Acorn, HPS	100	9,500	43	14.12	4.69	2.20	
	150	16,000	62	14.39	5.58	3.17	
	200	22,000	79	16.79	6.66	4.04	
	250	29,000	102	16.43	7.62	5.21	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	11.62	4.34	2.20	
	150	16,000	62	11.59	5.18	3.17	(R)
HADCO Techtra, HPS	100	9,500	43	20.37	5.52	2.20	(I)
	150	16,000	62	20.73	6.41	3.17	
	250	29,000	102	22.70	8.45	5.21	(I)
HADCO Westbrooke, HPS	70	6,300	30	12.98	3.96	1.53	(R)
	100	9,500	43	13.07	4.54	2.20	
	150	16,000	62	14.05	5.52	3.17	
	200	22,000	79	15.11	6.42	4.04	
	250	29,000	102	16.47	7.62	5.21	(R)(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	
Special Types							
Cobrahead, Metal Halide	150	10,000	60	$ 8.35	$ 4.94	$ 3.07	(I)
Flood, Metal Halide	350	30,000	139	13.13	9.04	7.10	(R)
Flood, HPS	750	105,000	285	23.70	17.44	14.56	(I)
Holophane Mongoose, HPS	150	16,000	62	12.15	5.27	3.17	(R)
	250	29,000	102	13.59	7.22	5.21	(R)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	3.27	
Ornamental Acorn	55	2,800	21	*	*	1.07	
Ornamental Acorn Twin	55	5,600	42	*	*	2.15	
Composite, Twin	140	6,815	54	*	*	2.76	
	175	9,815	66	*	*	3.37	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 6.67	$ 0.20	(R)(I)
	25	11.07	0.33	
	30	11.96	0.36	
	35	14.30	0.43	
Aluminum Davit	25	11.05	0.33	
	30	10.99	0.33	
	35	12.02	0.36	
	40	16.30	0.49	
Aluminum Double Davit	30	16.22	0.48	
Aluminum, HADCO, Fluted Victorian Ornamental	14	9.76	0.29	(R)(I)

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	$ 19.21	$ 0.57	(R)(I)
Aluminum, HADCO, Fluted Ornamental	16	9.98	0.30	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	20.41	0.61	
Aluminum, HADCO, Fluted Westbrooke	18	19.26	0.57	
Aluminum, HADCO, Non-Fluted, Westbrooke	18	20.41	0.61	
Aluminum, Painted Ornamental	35	32.80	0.98	
Concrete, Decorative Ameron	20	19.16	0.57	
Concrete, Ameron Post-Top	25	19.16	0.57	
Fiberglass, HADCO, Fluted Ornamental Black	14	11.81	0.35	
Fiberglass, Smooth	18	4.90	0.15	
Fiberglass, Regular,				
color may vary	22	4.38	0.13	
color may vary	35	7.19	0.21	
Fiberglass, Anchor Base, Gray	35	13.11	0.39	
Fiberglass, Direct Bury with Shroud	18	7.92	0.24	(R)(I)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$ 1.99	(I)
	175	7,000	66	$ 8.01	$ 4.88	3.37	
	250	10,000	94	*	*	4.80	
	400	21,000	147	12.94	9.15	7.51	
	1,000	55,000	374	24.94	21.05	19.11	(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	$ 7.31	$ 3.18	$ 1.53	(R)(I)
Mercury Vapor	175	7,000	66	9.11	4.98	3.37	(R)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	3.07	
	70	6,300	30	*	*	1.53	
	100	9,500	43	*	4.19	2.20	
	150	16,000	62	*	5.18	3.17	
	250	29,000	102	*	*	5.21	
	400	50,000	163	*	*	8.33	
Metal Halide	250	20,500	99	*	6.32	5.06	
	400	40,000	156	*	9.23	7.97	
Cobrahead, Metal Halide	175	12,000	71	8.95	5.35	3.63	(R)
Flood, Metal Halide	400	40,000	156	13.93	9.85	7.97	(I)
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.77	2.20	
100/150 Watt Ballast	100	9,500	43	*	3.77	2.20	
100/150 Watt Ballast	150	16,000	62	*	4.76	3.17	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$ 2.36	$ 1.63	
	165	12,000	60	*	3.95	3.07	
	165	12,000	60	$ 22.01	4.23	3.07	(R)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.70	3.17	
KIM Archetype, HPS	250	29,000	102	*	7.79	5.21	
	400	50,000	163	*	10.57	8.33	(I)

* Not offered

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$ 10.16	$ 3.60	$ 1.53	(R)(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	1.53	
Mercury Vapor	175	7,000	66	*	*	3.37	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	7.51	
Early American Post-Top, HPS							
Black	70	6,300	30	6.56	3.07	1.53	(R)
Rectangle Type	200	22,000	79	*	*	4.04	
Incandescent	92	1,000	31	*	*	1.58	
	182	2,500	62	*	*	3.17	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	8.41	4.92	3.37	(R)
Flood, HPS	70	6,300	30	6.11	2.98	1.53	
	100	9,500	43	6.74	3.76	2.20	
	200	22,000	79	9.86	5.74	4.04	(R)
Cobrahead, HPS							
Power Door	310	37,000	124	12.09	8.35	6.34	(I)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.20	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	4.39	
Compact Fluorescent	28	N/A	12	*	*	0.61	(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	$ 6.67	*	(R)
Bronze Alloy GardCo	12	*	$ 0.18	(I)
Concrete, Ornamental	35 or less	11.07	0.33	(R)
Steel, Painted Regular **	25	11.07	0.33	
Steel, Painted Regular **	30	11.96	0.36	(R)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.33	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.33	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.36	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.36	
Wood, Laminated without Mast Arm	20	4.91	0.15	(R)(I)
Wood, Laminated Street Light Only	20	4.91	*	
Wood, Curved Laminated	30	7.74	0.23	(I)
Wood, Painted Underground	35	5.59	0.17	(I)
Wood, Painted Street Light Only	35	5.59	*	(R)

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

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	2.195 ¢ 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	5.109 ¢ per kWh	(I)
Energy Charge	Provided by Energy Service Supplier	

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$133.00 per hour	$188.00 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	$ 3.61	(R)
LED	50	3,162	17	3.82	
LED	52	3,757	18	4.20	
LED	67	5,050	23	4.84	
LED	106	7,444	36	6.20	(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	$ 12.50	(R)
	70	4,332	24	14.47	
Westbrooke (Non-Flared)	53	5,079	18	16.57	
LED	69	6,661	24	16.29	
	85	8,153	29	16.75	
	136	12,687	46	20.69	
	206	18,159	70	21.85	
Westbrooke (Flared)	53	5,079	18	18.71	
LED	69	6,661	24	19.02	
	85	8,153	29	18.21	
	136	12,687	46	21.78	
	206	18,159	70	23.01	(R)

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	0.312 ¢ per kWh	Distribution Charge	(I)
15	0.561 ¢ per kWh	Distribution Charge	(R)
32	0.285 ¢ per kWh	Distribution Charge	(I)
38	0.360 ¢ per kWh	Distribution Charge	
47	0.673 ¢ per kWh	Distribution Charge	(I)
49	0.579 ¢ per kWh	Distribution Charge	(R)
75			
Secondary	0.174 ¢ per kWh	System Usage Charge	(I)
Primary	0.171 ¢ per kWh	System Usage Charge	
Subtransmission	0.168 ¢ per kWh	System Usage Charge	(I)

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	0.228	¢ per kWh	System Usage Charge	(I)
85				
Secondary	0.201	¢ per kWh	System Usage Charge	
Primary	0.197	¢ per kWh	System Usage Charge	
89				
Secondary	0.174	¢ per kWh	System Usage Charge	
Primary	0.171	¢ per kWh	System Usage Charge	
Subtransmission	0.168	¢ per kWh	System Usage Charge	
90	0.159	¢ per kWh	System Usage Charge	(I)
91	0.457	¢ per kWh	Distribution Charge	(R)
92	0.203	¢ per kWh	Distribution Charge	(I)
95	0.457	¢ per kWh	Distribution Charge	(R)
485				
Secondary	0.055	¢ per kWh	System Usage Charge	
Primary	0.055	¢ per kWh	System Usage Charge	
489				
Secondary	0.033	¢ per kWh	System Usage Charge	
Primary	0.033	¢ per kWh	System Usage Charge	
Subtransmission	0.033	¢ per kWh	System Usage Charge	
490	0.014	¢ per kWh	System Usage Charge	
491	0.315	¢ per kWh	Distribution Charge	(R)
492	0.056	¢ per kWh	Distribution Charge	(I)
495	0.315	¢ per kWh	Distribution Charge	(R)

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	0.418 ¢ per kWh	Distribution Charge	(R)
532	0.118 ¢ per kWh	Distribution Charge	(I)
538	0.203 ¢ per kWh	Distribution Charge	(I)
549	0.383 ¢ per kWh	Distribution Charge	(R)
575			
Secondary	0.033 ¢ per kWh	System Usage Charge	
Primary	0.033 ¢ per kWh	System Usage Charge	
Subtransmission	0.033 ¢ per kWh	System Usage Charge	(R)
583	0.064 ¢ per kWh	System Usage Charge	(I)
585			
Secondary	0.055 ¢ per kWh	System Usage Charge	(R)
Primary	0.055 ¢ per kWh	System Usage Charge	
590	0.014 ¢ per kWh	System Usage Charge	
591	0.315 ¢ per kWh	Distribution Charge	(R)
592	0.056 ¢ per kWh	Distribution Charge	(I)
595	0.315 ¢ per kWh	Distribution Charge	(R)

DO NOT BILL

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2016

		Forecast SDEC14E16		TOTAL ELECTRIC BILLS			
				CURRENT	PROPOSED	Change	
CATEGORY	RATE SCHEDULE	CUSTOMERS	MWH SALES	w/ Sch. 122a, 125	w/ Sch. 122a, 125	AMOUNT	PCT.
Residential	7	748,413	7,620,805	$913,144,457	$936,829,142	$23,684,685	2.6%
Employee Discount				($957,297)	($980,747)	($23,450)	
Subtotal				$912,187,160	$935,848,395	$23,661,235	2.6%
Outdoor Area Lighting	15	0	16,308	$3,628,230	$3,457,828	($170,401)	-4.7%
General Service <30 kW	32	90,384	1,599,950	$175,073,183	$181,832,054	$6,758,871	3.9%
Opt. Time-of-Day G.S. >30 kW	38	548	39,036	$5,250,625	$5,845,141	$594,515	11.3%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,845	$3,692,050	$3,702,753	$10,704	0.3%
Irrig. & Drain. Pump. > 30 kW	49	1,349	62,677	$7,829,234	$8,804,296	$975,063	12.5%
General Service 31-200 kW	83	11,029	2,795,179	$248,442,316	$256,033,100	$7,590,784	3.1%
General Service 201-4,000 kW							
Secondary	85-S	1,263	2,464,564	$194,212,818	$196,271,320	$2,058,502	1.1%
Primary	85-P	192	713,162	$53,271,439	$53,827,595	$556,156	1.0%
Schedule 89 > 4 MW							
Primary	89-P	18	851,370	$55,962,776	$56,187,831	$225,055	0.4%
Subtransmission	89-T	5	83,072	$7,061,664	$6,718,472	($343,192)	-4.9%
Schedule 90	90-P	4	1,498,007	$91,891,081	$92,359,227	$468,147	0.5%
Street & Highway Lighting	91/95	205	74,544	$14,054,838	$13,597,939	($456,900)	-3.3%
Traffic Signals	92	17	3,243	$250,708	$259,009	$8,302	3.3%
COS TOTALS		856,579	17,842,764	$1,772,808,122	$1,814,744,962	$41,936,841	2.4%
Direct Access Service 201-4,000 kW							
Secondary	485-S	159	438,339	$8,945,327	$8,401,715	($543,613)	
Primary	485-P	44	273,576	$5,786,884	$5,563,536	($223,348)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,393	$459,617	$348,435	($111,182)	
Primary	489-P	9	533,149	$6,903,263	$4,847,336	($2,055,927)	
Subtransmission	489-T	3	305,980	$3,014,567	$2,555,084	($459,483)	
DIRECT ACCESS TOTALS		216	1,565,436	$25,109,658	$21,716,106	($3,393,553)	
COS AND DA CYCLE TOTALS		856,795	19,408,200	$1,797,917,780	$1,836,461,068	$38,543,288	2.1%

TABLE 2
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2016

CATEGORY	RATE SCHEDULE	Forecast SDEC14E16 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT w/ Sch. 122a, 125, 102	TOTAL ELECTRIC BILLS PROPOSED w/ Sch. 122a, 125, 102	Change AMOUNT	Change PCT.
Residential	7	748,413	7,620,805	$859,879,044	$869,982,606	$10,103,562	1.2%
Employee Discount				($906,214)	($916,639)	($10,425)	
Subtotal				$858,972,830	$869,065,967	$10,093,137	1.2%
Outdoor Area Lighting	15	0	16,308	$3,602,180	$3,425,099	($177,082)	-4.9%
General Service <30 kW	32	90,384	1,599,950	$173,426,892	$179,763,576	$6,336,685	3.7%
Opt. Time-of-Day G.S. >30 kW	38	548	39,036	$5,244,395	$5,837,313	$592,918	11.3%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,845	$3,559,391	$3,536,075	($23,316)	-0.7%
Irrig. & Drain. Pump. > 30 kW	49	1,349	62,677	$7,448,006	$8,325,303	$877,298	11.8%
General Service 31-200 kW	83	11,029	2,795,179	$246,795,399	$253,963,836	$7,168,437	2.9%
General Service 201-4,000 kW							
Secondary	85-S	1,263	2,464,564	$193,826,322	$195,785,708	$1,959,386	1.0%
Primary	85-P	192	713,162	$53,212,473	$53,753,507	$541,034	1.0%
Schedule 89 > 4 MW							
Primary	89-P	18	851,370	$55,962,776	$56,187,831	$225,055	0.4%
Subtransmission	89-T	5	83,072	$7,061,664	$6,718,472	($343,192)	-4.9%
Schedule 90	90-P	4	1,498,007	$91,891,081	$92,359,227	$468,147	0.5%
Street & Highway Lighting	91/95	205	74,544	$14,054,838	$13,597,939	($456,900)	-3.3%
Traffic Signals	92	17	3,243	$250,708	$259,009	$8,302	3.3%
COS TOTALS		856,579	17,842,764	$1,715,308,954	$1,742,578,863	$27,269,909	1.6%
Direct Access Service 201-4,000 kW							
Secondary	485-S	159	438,339	$8,945,327	$8,401,715	($543,613)	
Primary	485-P	44	273,576	$5,786,884	$5,563,536	($223,348)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,393	$459,617	$348,435	($111,182)	
Primary	489-P	9	533,149	$6,903,263	$4,847,336	($2,055,927)	
Subtransmission	489-T	3	305,980	$3,014,567	$2,555,084	($459,483)	
DIRECT ACCESS TOTALS		216	1,565,436	$25,109,658	$21,716,106	($3,393,553)	
COS AND DA CYCLE TOTALS		856,795	19,408,200	$1,740,418,613	$1,764,294,969	$23,876,357	1.4%

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2016

		Forecast SDEC14E16		TOTAL ELECTRIC BILLS			
				CURRENT	PROPOSED		
CATEGORY	RATE SCHEDULE	CUSTOMERS	MWH SALES	all supplementals except LIA, PPC & Sch 109	all supplementals except LIA, PPC & Sch 109	Change AMOUNT	PCT.
Residential	7	748,413	7,620,805	$866,356,728	$855,960,324	($10,396,404)	-1.2%
Employee Discount				($913,107)	($901,716)	$11,391	
Subtotal				$865,443,621	$855,058,608	($10,385,013)	-1.2%
Outdoor Area Lighting	15	0	16,308	$3,628,870	$3,408,619	($220,251)	-6.1%
General Service <30 kW	32	90,384	1,599,950	$173,283,588	$176,500,702	$3,217,114	1.9%
Opt. Time-of-Day G.S. >30 kW	38	548	39,036	$5,289,988	$5,783,046	$493,058	9.3%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,845	$3,585,864	$3,511,270	($74,594)	-2.1%
Irrig. & Drain. Pump. > 30 kW	49	1,349	62,677	$7,515,509	$8,240,676	$725,168	9.6%
General Service 31-200 kW	83	11,029	2,795,179	$249,645,056	$250,551,785	$906,728	0.4%
General Service 201-4,000 kW							
Secondary	85-S	1,263	2,464,564	$196,121,430	$192,790,815	($3,330,615)	-1.7%
Primary	85-P	192	713,162	$53,683,677	$52,896,527	($787,150)	-1.5%
Schedule 89 > 4 MW							
Primary	89-P	18	851,370	$56,124,536	$55,149,160	($975,376)	-1.7%
Subtransmission	89-T	5	83,072	$7,078,279	$6,619,813	($458,466)	-6.5%
Schedule 90	90-P	4	1,498,007	$92,205,662	$90,681,459	($1,524,203)	-1.7%
Street & Highway Lighting	91/95	205	74,544	$14,165,164	$13,521,903	($643,261)	-4.5%
Traffic Signals	92	17	3,243	$253,983	$255,475	$1,492	0.6%
COS TOTALS		856,579	17,842,764	$1,728,025,228	$1,714,969,859	($13,055,369)	-0.8%
Direct Access Service 201-4,000 kW							
Secondary	485-S	159	438,339	$8,590,256	$7,676,260	($913,996)	
Primary	485-P	44	273,576	$5,564,975	$5,119,580	($445,395)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,393	$446,088	$324,543	($121,545)	
Primary	489-P	9	533,149	$6,418,097	$3,988,966	($2,429,131)	
Subtransmission	489-T	3	305,980	$2,742,245	$2,071,636	($670,609)	
DIRECT ACCESS TOTALS		216	1,565,436	$23,761,662	$19,180,986	($4,580,676)	
COS AND DA CYCLE TOTALS		856,795	19,408,200	$1,751,786,890	$1,734,150,845	($17,636,045)	-1.0%

TABLE 4
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2016

CATEGORY	RATE SCHEDULE	Forecast SDEC14E16 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	748,413	7,620,805	$890,590,890	$880,194,485	($10,396,404)	-1.2%
Employee Discount				($913,107)	($901,716)	$11,391	
Subtotal				$889,677,782	$879,292,769	($10,385,013)	-1.2%
Outdoor Area Lighting	15	0	16,308	$3,720,472	$3,500,221	($220,251)	-5.9%
General Service <30 kW	32	90,384	1,599,950	$177,983,371	$181,200,485	$3,217,114	1.8%
Opt. Time-of-Day G.S. >30 kW	38	548	39,036	$5,425,870	$5,918,927	$493,058	9.1%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,845	$3,672,577	$3,597,982	($74,594)	-2.0%
Irrig. & Drain. Pump. > 30 kW	49	1,349	62,677	$7,699,051	$8,424,219	$725,168	9.4%
General Service 31-200 kW	83	11,029	2,795,179	$256,178,020	$257,084,749	$906,728	0.4%
General Service 201-4,000 kW							
Secondary	85-S	1,263	2,464,564	$200,716,499	$197,385,884	($3,330,615)	-1.7%
Primary	85-P	192	713,162	$54,524,372	$53,737,222	($787,150)	-1.4%
Schedule 89 > 4 MW							
Primary	89-P	18	851,370	$56,124,536	$55,149,160	($975,376)	-1.7%
Subtransmission	89-T	5	83,072	$7,078,279	$6,619,813	($458,466)	-6.5%
Schedule 90	90-P	4	1,498,007	$92,205,662	$90,681,459	($1,524,203)	-1.7%
Street & Highway Lighting	91/95	205	74,544	$14,537,886	$13,894,625	($643,261)	-4.4%
Traffic Signals	92	17	3,243	$260,663	$262,155	$1,492	0.6%
COS TOTALS		856,579	17,842,764	$1,769,805,039	$1,756,749,671	($13,055,369)	-0.7%
Direct Access Service 201-4,000 kW							
Secondary	485-S	159	438,339	$9,228,297	$8,314,301	($913,996)	
Primary	485-P	44	273,576	$5,874,711	$5,429,315	($445,395)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,393	$446,088	$324,543	($121,545)	
Primary	489-P	9	533,149	$6,418,097	$3,988,966	($2,429,131)	
Subtransmission	489-T	3	305,980	$2,742,245	$2,071,636	($670,609)	
DIRECT ACCESS TOTALS		216	1,565,436	$24,709,438	$20,128,762	($4,580,676)	
COS AND DA CYCLE TOTALS		856,795	19,408,200	$1,794,514,477	$1,776,878,432	($17,636,045)	-1.0%

TABLE 5
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS INCLUDING CARTY
2016

CATEGORY	RATE SCHEDULE	Forecast SDEC14E16 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	748,413	7,620,805	$890,590,890	$918,222,304	$27,631,415	3.1%
Employee Discount				($913,107)	($942,186)	($29,079)	
Subtotal				$889,677,782	$917,280,118	$27,602,336	3.1%
Outdoor Area Lighting	15	0	16,308	$3,720,472	$3,565,779	($154,692)	-4.2%
General Service <30 kW	32	90,384	1,599,950	$177,983,371	$188,672,253	$10,688,882	6.0%
Opt. Time-of-Day G.S. >30 kW	38	548	39,036	$5,425,870	$6,115,668	$689,798	12.7%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,845	$3,672,577	$3,695,328	$22,751	0.6%
Irrig. & Drain. Pump. > 30 kW	49	1,349	62,677	$7,699,051	$8,740,113	$1,041,062	13.5%
General Service 31-200 kW	83	11,029	2,795,179	$256,178,020	$269,858,719	$13,680,699	5.3%
General Service 201-4,000 kW							
Secondary	85-S	1,263	2,464,564	$200,716,499	$208,427,132	$7,710,633	3.8%
Primary	85-P	192	713,162	$54,524,372	$56,853,739	$2,329,368	4.3%
Schedule 89 > 4 MW							
Primary	89-P	18	851,370	$56,124,536	$58,775,995	$2,651,458	4.7%
Subtransmission	89-T	5	83,072	$7,078,279	$6,973,700	($104,579)	-1.5%
Schedule 90	90-P	4	1,498,007	$92,205,662	$96,733,409	$4,527,747	4.9%
Street & Highway Lighting	91/95	205	74,544	$14,537,886	$14,194,294	($343,592)	-2.4%
Traffic Signals	92	17	3,243	$260,663	$275,483	$14,820	5.7%
COS TOTALS		856,579	17,842,764	$1,769,805,039	$1,840,161,730	$70,356,691	4.0%
Direct Access Service 201-4,000 kW							
Secondary	485-S	159	438,339	$9,228,297	$8,330,353	($897,944)	
Primary	485-P	44	273,576	$5,874,711	$5,569,630	($305,081)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,393	$446,088	$324,399	($121,689)	
Primary	489-P	9	533,149	$6,418,097	$3,983,635	($2,434,463)	
Subtransmission	489-T	3	305,980	$2,742,245	$2,068,576	($673,669)	
DIRECT ACCESS TOTALS		216	1,565,436	$24,709,438	$20,276,593	($4,432,845)	
COS AND DA CYCLE TOTALS		856,795	19,408,200	$1,794,514,477	$1,860,438,323	$65,923,846	3.7%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 7

Net Monthly Bill

kWh	Current Prices	Proposed Prices	Percent Difference
50	$16.41	$17.27	5.2%
100	$21.66	$22.39	3.4%
200	$32.16	$32.60	1.4%
250	$37.44	$37.73	0.8%
300	$42.68	$42.80	0.3%
400	$53.20	$53.03	-0.3%
500	$63.75	$63.26	-0.8%
600	$74.25	$73.47	-1.1%
700	$84.77	$83.70	-1.3%
800	$95.29	$93.91	-1.4%
840	$99.49	$97.98	-1.5%
900	$105.79	$104.11	-1.6%
1,000	$116.31	$114.33	-1.7%
1,100	$128.46	$126.41	-1.6%
1,200	$140.58	$138.46	-1.5%
1,300	$152.73	$150.52	-1.4%
1,400	$164.87	$162.58	-1.4%
1,500	$177.04	$174.67	-1.3%
1,600	$189.17	$186.74	-1.3%
1,700	$201.31	$198.80	-1.2%
1,800	$213.46	$210.86	-1.2%
2,000	$237.72	$234.98	-1.2%
2,300	$274.15	$271.17	-1.1%
2,750	$328.80	$325.49	-1.0%
3,000	$359.14	$355.64	-1.0%
3,500	$419.87	$415.98	-0.9%
4,000	$480.55	$476.29	-0.9%
4,500	$541.28	$536.63	-0.9%
5,000	$601.97	$596.94	-0.8%
7,500	$905.53	$898.58	-0.8%
10,000	$1,209.03	$1,200.20	-0.7%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 1-phase Service

	Net Monthly Billing (without RPA credit)			Net Monthly Billing (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
500	$69.23	$71.17	2.8%	$65.63	$66.65	1.6%
600	$79.95	$82.08	2.7%	$75.63	$76.66	1.4%
700	$90.71	$93.04	2.6%	$85.68	$86.72	1.2%
800	$101.47	$103.97	2.5%	$95.72	$96.74	1.1%
900	$112.23	$114.93	2.4%	$105.76	$106.80	1.0%
1,000	$122.97	$125.86	2.4%	$115.78	$116.82	0.9%
1,500	$176.75	$180.55	2.1%	$165.96	$166.99	0.6%
1,750	$203.63	$207.91	2.1%	$191.04	$192.10	0.6%
2,000	$230.49	$235.23	2.1%	$216.11	$217.16	0.5%
2,500	$284.27	$289.92	2.0%	$266.30	$267.34	0.4%
3,500	$391.79	$399.30	1.9%	$366.63	$367.68	0.3%
4,000	$445.54	$453.98	1.9%	$416.78	$417.85	0.3%
4,500	$499.31	$508.67	1.9%	$466.96	$468.02	0.2%
5,000	$553.06	$563.36	1.9%	$517.11	$518.19	0.2%
6,000	$632.91	$641.32	1.3%	$589.78	$587.12	-0.5%
7,000	$712.77	$719.28	0.9%	$662.44	$656.05	-1.0%
8,000	$792.62	$797.24	0.6%	$735.11	$724.97	-1.4%
9,000	$872.48	$875.20	0.3%	$807.78	$793.90	-1.7%
10,000	$952.34	$953.16	0.1%	$880.44	$862.83	-2.0%
14,000	$1,271.76	$1,265.00	-0.5%	$1,171.11	$1,138.54	-2.8%
15,000	$1,351.61	$1,342.96	-0.6%	$1,243.77	$1,207.47	-2.9%
20,000	$1,750.89	$1,732.77	-1.0%	$1,607.11	$1,552.10	-3.4%
21,900	$1,902.63	$1,880.90	-1.1%	$1,745.19	$1,683.08	-3.6%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 3-phase Service

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
500	$74.38	$77.35	4.0%	$70.78	$72.83	2.9%
600	$85.10	$88.26	3.7%	$80.78	$82.84	2.6%
700	$95.86	$99.22	3.5%	$90.83	$92.90	2.3%
800	$106.62	$110.15	3.3%	$100.87	$102.92	2.0%
900	$117.38	$121.11	3.2%	$110.91	$112.98	1.9%
1,000	$128.12	$132.04	3.1%	$120.93	$123.00	1.7%
1,500	$181.90	$186.73	2.7%	$171.11	$173.17	1.2%
1,750	$208.78	$214.09	2.5%	$196.19	$198.28	1.1%
2,000	$235.64	$241.41	2.4%	$221.26	$223.34	0.9%
2,500	$289.42	$296.10	2.3%	$271.45	$273.52	0.8%
3,500	$396.94	$405.48	2.2%	$371.78	$373.86	0.6%
4,000	$450.69	$460.16	2.1%	$421.93	$424.03	0.5%
4,500	$504.46	$514.85	2.1%	$472.11	$474.20	0.4%
5,000	$558.21	$569.54	2.0%	$522.26	$524.37	0.4%
6,000	$638.06	$647.50	1.5%	$594.93	$593.30	-0.3%
7,000	$717.92	$725.46	1.1%	$667.59	$662.23	-0.8%
8,000	$797.77	$803.42	0.7%	$740.26	$731.15	-1.2%
9,000	$877.63	$881.38	0.4%	$812.93	$800.08	-1.6%
10,000	$957.49	$959.34	0.2%	$885.59	$869.01	-1.9%
14,000	$1,276.91	$1,271.18	-0.4%	$1,176.26	$1,144.72	-2.7%
15,000	$1,356.76	$1,349.14	-0.6%	$1,248.92	$1,213.65	-2.8%
20,000	$1,756.04	$1,738.95	-1.0%	$1,612.26	$1,558.28	-3.3%
21,900	$1,907.78	$1,887.08	-1.1%	$1,750.34	$1,689.26	-3.5%

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	$44.51	$52.93	18.9%	$44.15	$52.48	18.9%
10	100	$52.95	$60.52	14.3%	$52.23	$59.61	14.1%
10	500	$120.55	$121.30	0.6%	$116.96	$116.77	-0.2%
10	1,000	$194.74	$192.10	-1.4%	$187.55	$183.07	-2.4%
10	2,000	$343.11	$333.72	-2.7%	$328.73	$315.65	-4.0%
10	5,000	$788.24	$758.58	-3.8%	$752.29	$713.41	-5.2%
20	100	$52.95	$60.52	14.3%	$52.23	$59.61	14.1%
20	200	$69.84	$75.71	8.4%	$68.40	$73.91	8.1%
20	500	$120.55	$121.30	0.6%	$116.96	$116.77	-0.2%
20	1,000	$205.03	$197.24	-3.8%	$197.84	$188.21	-4.9%
20	2,000	$353.40	$338.86	-4.1%	$339.02	$320.79	-5.4%
20	5,000	$798.53	$763.72	-4.4%	$762.58	$718.55	-5.8%
20	8,000	$1,243.66	$1,188.57	-4.4%	$1,186.14	$1,116.31	-5.9%
30	150	$61.41	$68.13	10.9%	$60.33	$66.77	10.7%
30	500	$120.55	$121.30	0.6%	$116.96	$116.77	-0.2%
30	1,000	$205.03	$197.24	-3.8%	$197.84	$188.21	-4.9%
30	3,000	$512.09	$485.64	-5.2%	$490.52	$458.54	-6.5%
30	5,000	$808.84	$768.88	-4.9%	$772.89	$723.71	-6.4%
30	8,000	$1,253.97	$1,193.73	-4.8%	$1,196.45	$1,121.47	-6.3%
30	10,000	$1,550.72	$1,476.97	-4.8%	$1,478.83	$1,386.64	-6.2%
30	15,000	$2,292.60	$2,185.07	-4.7%	$2,184.76	$2,049.57	-6.2%

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	$696.68	$768.07	10.2%	$659.94	$721.91	9.4%
40%	35	10,220	$1,316.14	$1,466.63	11.4%	$1,242.66	$1,374.31	10.6%
60%	35	15,330	$1,935.56	$2,165.16	11.9%	$1,825.35	$2,026.68	11.0%
80%	35	20,440	$2,554.99	$2,863.70	12.1%	$2,408.04	$2,679.06	11.3%
20%	50	7,300	$977.61	$1,075.17	10.0%	$925.13	$1,009.23	9.1%
40%	50	14,600	$1,862.53	$2,073.10	11.3%	$1,757.56	$1,941.22	10.4%
60%	50	21,900	$2,747.44	$3,071.01	11.8%	$2,589.99	$2,873.19	10.9%
80%	50	29,200	$3,632.33	$4,068.93	12.0%	$3,422.40	$3,805.16	11.2%
20%	70	10,220	$1,352.19	$1,484.65	9.8%	$1,278.71	$1,392.33	8.9%
40%	70	20,440	$2,591.03	$2,881.72	11.2%	$2,444.08	$2,697.08	10.4%
60%	70	30,660	$3,829.91	$4,278.81	11.7%	$3,609.48	$4,001.86	10.9%
80%	70	40,880	$5,068.80	$5,675.89	12.0%	$4,774.90	$5,306.62	11.1%
20%	100	14,600	$1,914.03	$2,098.85	9.7%	$1,809.06	$1,966.97	8.7%
40%	100	29,200	$3,683.83	$4,094.68	11.2%	$3,473.90	$3,830.91	10.3%
60%	100	43,800	$5,453.67	$6,090.53	11.7%	$5,138.77	$5,694.87	10.8%
80%	100	58,400	$7,223.47	$8,086.35	11.9%	$6,803.61	$7,558.82	11.1%
20%	200	29,200	$3,786.83	$4,146.18	9.5%	$3,576.90	$3,882.41	8.5%
40%	200	58,400	$7,326.47	$8,137.85	11.1%	$6,906.61	$7,610.32	10.2%
60%	200	87,600	$10,866.12	$12,129.55	11.6%	$10,236.33	$11,338.25	10.8%
80%	200	116,800	$14,405.76	$16,121.23	11.9%	$13,566.04	$15,066.16	11.1%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 38, 3-phase Service
Bill comparison assumes 51% on peak and 49% off peak energy consumption

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
1,000	$163.88	$176.93	8.0%	$156.69	$167.89	7.1%
3,000	$440.13	$479.28	8.9%	$418.56	$452.18	8.0%
5,000	$716.38	$781.64	9.1%	$680.44	$736.47	8.2%
7,000	$992.64	$1,083.99	9.2%	$942.31	$1,020.76	8.3%
10,000	$1,407.02	$1,537.52	9.3%	$1,335.13	$1,447.19	8.4%
13,000	$1,821.40	$1,991.05	9.3%	$1,727.94	$1,873.62	8.4%
14,000	$1,959.53	$2,142.23	9.3%	$1,858.88	$2,015.76	8.4%
16,000	$2,235.78	$2,444.58	9.3%	$2,120.75	$2,300.05	8.5%
21,000	$2,926.41	$3,200.47	9.4%	$2,775.44	$3,010.77	8.5%
25,000	$3,478.92	$3,805.18	9.4%	$3,299.19	$3,579.35	8.5%
30,000	$4,169.56	$4,561.06	9.4%	$3,953.88	$4,290.07	8.5%
35,000	$4,860.19	$5,316.95	9.4%	$4,608.56	$5,000.79	8.5%
40,000	$5,550.83	$6,072.83	9.4%	$5,263.25	$5,711.51	8.5%
45,000	$6,241.46	$6,828.72	9.4%	$5,917.94	$6,422.23	8.5%
50,000	$6,932.11	$7,584.61	9.4%	$6,572.64	$7,132.96	8.5%
75,000	$10,385.27	$11,364.03	9.4%	$9,846.06	$10,686.54	8.5%
100,000	$13,838.44	$15,143.45	9.4%	$13,119.50	$14,240.14	8.5%
150,000	$20,744.80	$22,702.31	9.4%	$19,666.39	$21,347.35	8.5%
200,000	$27,651.13	$30,261.15	9.4%	$26,213.25	$28,454.53	8.6%
300,000	$41,463.82	$45,378.85	9.4%	$39,307.00	$42,668.92	8.6%
400,000	$55,276.51	$60,496.55	9.4%	$52,400.75	$56,883.31	8.6%
500,000	$69,089.20	$75,614.25	9.4%	$65,494.50	$71,097.70	8.6%
750,000	$100,400.89	$110,736.94	10.3%	$95,008.84	$103,962.11	9.4%
1,000,000	$133,859.25	$147,640.65	10.3%	$126,669.85	$138,607.55	9.4%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Secondary, 3 phase service.
Bill comparison assumes 63% on peak and 37% off peak energy consumption

			Net Monthly Billing (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
30%	30	6,570	$704.59	$710.49	0.8%	$657.36	$651.15	-0.9%
30%	50	10,950	$1,144.81	$1,154.65	0.9%	$1,066.09	$1,055.73	-1.0%
30%	75	16,425	$1,695.04	$1,709.81	0.9%	$1,576.95	$1,561.44	-1.0%
30%	100	21,900	$2,245.31	$2,265.00	0.9%	$2,087.86	$2,067.18	-1.0%
30%	135	29,565	$3,015.65	$3,042.24	0.9%	$2,803.10	$2,775.17	-1.0%
30%	175	38,325	$3,896.05	$3,930.51	0.9%	$3,620.52	$3,584.31	-1.0%
30%	200	43,800	$4,446.30	$4,485.68	0.9%	$4,131.41	$4,090.03	-1.0%
50%	30	10,950	$1,028.42	$1,032.69	0.4%	$949.70	$933.78	-1.7%
50%	50	18,250	$1,684.49	$1,691.63	0.4%	$1,553.28	$1,526.77	-1.7%
50%	75	27,375	$2,504.60	$2,515.30	0.4%	$2,307.79	$2,268.02	-1.7%
50%	100	36,500	$3,324.69	$3,338.96	0.4%	$3,062.28	$3,009.25	-1.7%
50%	135	49,275	$4,472.82	$4,492.07	0.4%	$4,118.56	$4,046.96	-1.7%
50%	175	63,875	$5,784.96	$5,809.94	0.4%	$5,325.74	$5,232.96	-1.7%
50%	200	73,000	$6,605.06	$6,633.61	0.4%	$6,080.23	$5,974.19	-1.7%
70%	30	15,330	$1,352.21	$1,354.87	0.2%	$1,242.00	$1,216.40	-2.1%
70%	50	25,550	$2,224.17	$2,228.61	0.2%	$2,040.48	$1,997.81	-2.1%
70%	75	38,325	$3,314.10	$3,320.75	0.2%	$3,038.57	$2,974.55	-2.1%
70%	100	51,100	$4,404.06	$4,412.92	0.2%	$4,036.68	$3,951.33	-2.1%
70%	135	68,985	$5,929.96	$5,941.92	0.2%	$5,434.00	$5,318.77	-2.1%
70%	175	89,425	$7,673.87	$7,689.37	0.2%	$7,030.95	$6,881.58	-2.1%
70%	200	102,200	$8,763.81	$8,781.54	0.2%	$8,029.05	$7,858.36	-2.1%
90%	30	19,710	$1,676.04	$1,677.08	0.1%	$1,534.33	$1,499.03	-2.3%
90%	50	32,850	$2,763.86	$2,765.59	0.1%	$2,527.70	$2,468.85	-2.3%
90%	75	49,275	$4,123.65	$4,126.21	0.1%	$3,769.39	$3,681.11	-2.3%
90%	100	65,700	$5,483.45	$5,486.88	0.1%	$5,011.10	$4,893.40	-2.3%
90%	135	88,695	$7,387.11	$7,391.76	0.1%	$6,749.45	$6,590.56	-2.4%
90%	175	114,975	$9,562.76	$9,568.80	0.1%	$8,736.15	$8,530.22	-2.4%
90%	200	131,400	$10,922.55	$10,929.46	0.1%	$9,977.86	$9,742.51	-2.4%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, Secondary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Net Monthly Bill Proposed Prices	Percent Difference
30%	200	43,800	$4,506.66	$4,488.89	-0.4%
30%	300	65,700	$6,461.30	$6,419.22	-0.7%
30%	500	109,500	$10,370.57	$10,279.82	-0.9%
30%	700	153,300	$14,279.81	$14,140.42	-1.0%
30%	800	175,200	$16,234.44	$16,070.73	-1.0%
30%	900	197,100	$18,189.08	$18,001.02	-1.0%
30%	1,000	219,000	$20,143.69	$19,931.33	-1.1%
30%	1,500	328,500	$29,916.86	$29,582.85	-1.1%
30%	2,000	438,000	$39,689.99	$39,234.35	-1.1%
30%	4,000	876,000	$76,274.76	$75,973.21	-0.4%
50%	200	73,000	$6,422.04	$6,337.52	-1.3%
50%	300	109,500	$9,334.39	$9,192.14	-1.5%
50%	500	182,500	$15,159.03	$14,901.37	-1.7%
50%	700	255,500	$20,983.67	$20,610.58	-1.8%
50%	800	292,000	$23,895.98	$23,465.19	-1.8%
50%	900	328,500	$26,808.32	$26,319.81	-1.8%
50%	1,000	365,000	$29,720.62	$29,174.41	-1.8%
50%	1,500	547,500	$44,282.25	$43,447.48	-1.9%
50%	2,000	730,000	$58,843.84	$57,720.52	-1.9%
50%	4,000	1,460,000	$112,680.60	$111,470.76	-1.1%
70%	200	102,200	$8,337.43	$8,186.14	-1.8%
70%	300	153,300	$12,207.45	$11,965.06	-2.0%
70%	500	255,500	$19,947.49	$19,522.90	-2.1%
70%	700	357,700	$27,687.51	$27,080.75	-2.2%
70%	800	408,800	$31,557.52	$30,859.65	-2.2%
70%	900	459,900	$35,427.54	$34,638.58	-2.2%
70%	1,000	511,000	$39,297.55	$38,417.50	-2.2%
70%	1,500	766,500	$56,453.29	$55,678.30	-1.4%
70%	2,000	1,022,000	$75,060.92	$74,017.30	-1.4%
70%	4,000	2,044,000	$149,024.43	$146,906.30	-1.4%
90%	200	131,400	$10,252.80	$10,034.74	-2.1%
90%	300	197,100	$15,080.54	$14,737.98	-2.3%
90%	500	328,500	$24,735.96	$24,144.45	-2.4%
90%	700	459,900	$34,391.36	$33,550.90	-2.4%
90%	800	525,600	$39,219.09	$38,254.13	-2.5%
90%	900	591,300	$44,046.77	$42,957.35	-2.5%
90%	1,000	657,000	$48,874.48	$47,660.58	-2.5%
90%	1,500	985,500	$70,191.73	$69,076.12	-1.6%
90%	2,000	1,314,000	$93,232.84	$91,735.07	-1.6%
90%	4,000	2,628,000	$185,368.27	$182,341.84	-1.6%

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	$4,449.75	$4,438.82	-0.2%
30%	300	65,700	$6,360.48	$6,328.64	-0.5%
30%	500	109,500	$10,181.94	$10,108.28	-0.7%
30%	700	153,300	$14,003.41	$13,887.90	-0.8%
30%	800	175,200	$15,914.13	$15,777.71	-0.9%
30%	900	197,100	$17,824.86	$17,667.54	-0.9%
30%	1,000	219,000	$19,735.58	$19,557.34	-0.9%
30%	1,500	328,500	$29,289.22	$29,006.42	-1.0%
30%	2,000	438,000	$38,842.85	$38,455.49	-1.0%
30%	4,000	876,000	$74,549.59	$74,384.58	-0.2%
50%	200	73,000	$6,329.95	$6,254.06	-1.2%
50%	300	109,500	$9,180.78	$9,051.50	-1.4%
50%	500	182,500	$14,882.43	$14,646.36	-1.6%
50%	700	255,500	$20,584.09	$20,241.21	-1.7%
50%	800	292,000	$23,434.91	$23,038.65	-1.7%
50%	900	328,500	$26,285.74	$25,836.08	-1.7%
50%	1,000	365,000	$29,136.56	$28,633.51	-1.7%
50%	1,500	547,500	$43,390.69	$42,620.67	-1.8%
50%	2,000	730,000	$57,644.82	$56,607.82	-1.8%
50%	4,000	1,460,000	$110,251.65	$109,214.44	-0.9%
70%	200	102,200	$8,210.15	$8,069.30	-1.7%
70%	300	153,300	$12,001.09	$11,774.34	-1.9%
70%	500	255,500	$19,582.93	$19,184.43	-2.0%
70%	700	357,700	$27,164.78	$26,594.53	-2.1%
70%	800	408,800	$30,955.69	$30,299.57	-2.1%
70%	900	459,900	$34,746.62	$34,004.63	-2.1%
70%	1,000	511,000	$38,537.54	$37,709.67	-2.1%
70%	1,500	766,500	$55,297.82	$54,601.10	-1.3%
70%	2,000	1,022,000	$73,510.01	$72,570.75	-1.3%
70%	4,000	2,044,000	$145,891.71	$143,982.30	-1.3%
90%	200	131,400	$10,090.34	$9,884.52	-2.0%
90%	300	197,100	$14,821.38	$14,497.20	-2.2%
90%	500	328,500	$24,283.42	$23,722.52	-2.3%
90%	700	459,900	$33,745.46	$32,947.85	-2.4%
90%	800	525,600	$38,476.50	$37,560.51	-2.4%
90%	900	591,300	$43,207.52	$42,173.17	-2.4%
90%	1,000	657,000	$47,938.53	$46,785.83	-2.4%
90%	1,500	985,500	$68,772.35	$67,748.55	-1.5%
90%	2,000	1,314,000	$91,330.04	$89,954.68	-1.5%
90%	4,000	2,628,000	$181,531.77	$178,750.15	-1.5%

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

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Net Monthly Bill Proposed Prices	Percent Difference
30%	4,000	876,000	$77,174.19	$72,361.79	-6.2%
30%	7,500	1,642,500	$137,630.02	$132,950.78	-3.4%
30%	10,000	2,190,000	$180,768.44	$176,184.32	-2.5%
30%	15,000	3,285,000	$267,045.31	$262,651.43	-1.6%
30%	20,000	4,380,000	$353,322.17	$349,118.54	-1.2%
50%	4,000	1,460,000	$111,769.46	$107,113.45	-4.2%
50%	7,500	2,737,500	$202,379.89	$197,993.89	-2.2%
50%	10,000	3,650,000	$267,101.60	$262,908.47	-1.6%
50%	15,000	5,475,000	$396,545.04	$392,737.65	-1.0%
50%	20,000	7,300,000	$525,988.49	$522,566.83	-0.7%
70%	4,000	2,044,000	$146,302.72	$141,803.10	-3.1%
70%	7,500	3,832,500	$267,129.76	$263,037.00	-1.5%
70%	10,000	5,110,000	$353,434.75	$349,632.61	-1.1%
70%	15,000	7,665,000	$526,044.78	$522,823.87	-0.6%
70%	20,000	10,220,000	$698,654.81	$696,015.12	-0.4%
90%	4,000	2,628,000	$180,835.98	$176,492.76	-2.4%
90%	7,500	4,927,500	$331,879.62	$328,080.11	-1.1%
90%	10,000	6,570,000	$439,767.91	$436,356.76	-0.8%
90%	15,000	9,855,000	$655,544.52	$652,910.09	-0.4%
90%	20,000	13,140,000	$871,321.12	$869,463.41	-0.2%

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	$75,165.90	$69,879.69	-7.0%
30%	7,500	1,642,500	$134,360.15	$129,243.15	-3.8%
30%	10,000	2,190,000	$176,597.45	$171,601.33	-2.8%
30%	15,000	3,285,000	$261,072.08	$256,317.70	-1.8%
30%	20,000	4,380,000	$345,546.70	$341,034.07	-1.3%
50%	4,000	1,460,000	$109,129.57	$103,999.76	-4.7%
50%	7,500	2,737,500	$197,925.78	$193,102.02	-2.4%
50%	10,000	3,650,000	$261,351.62	$256,746.49	-1.8%
50%	15,000	5,475,000	$388,203.33	$384,035.44	-1.1%
50%	20,000	7,300,000	$515,055.04	$511,324.38	-0.7%
70%	4,000	2,044,000	$143,031.24	$138,057.82	-3.5%
70%	7,500	3,832,500	$261,491.40	$256,960.88	-1.7%
70%	10,000	5,110,000	$346,105.79	$341,891.65	-1.2%
70%	15,000	7,665,000	$515,334.58	$511,753.17	-0.7%
70%	20,000	10,220,000	$684,563.38	$681,614.69	-0.4%
90%	4,000	2,628,000	$176,932.90	$172,115.88	-2.7%
90%	7,500	4,927,500	$325,057.03	$320,819.75	-1.3%
90%	10,000	6,570,000	$430,859.96	$427,036.80	-0.9%
90%	15,000	9,855,000	$642,465.83	$639,470.90	-0.5%
90%	20,000	13,140,000	$854,071.71	$851,905.00	-0.3%

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	$69,868.32	$66,066.59	-5.4%
30%	5,000	1,095,000	$85,320.60	$81,740.07	-4.2%
30%	10,000	2,190,000	$162,272.01	$159,797.43	-1.5%
30%	20,000	4,380,000	$316,174.81	$315,912.16	-0.1%
30%	40,000	8,760,000	$623,980.42	$628,141.62	0.7%
30%	50,000	10,950,000	$777,883.23	$784,256.36	0.8%
30%	70,000	15,330,000	$1,085,688.84	$1,096,485.82	1.0%
50%	4,000	1,460,000	$103,362.80	$99,711.45	-3.5%
50%	5,000	1,825,000	$127,111.21	$123,718.64	-2.7%
50%	10,000	3,650,000	$245,853.21	$243,754.59	-0.9%
50%	20,000	7,300,000	$483,337.22	$483,826.47	0.1%
50%	40,000	14,600,000	$958,305.24	$963,970.24	0.6%
50%	50,000	18,250,000	$1,195,789.25	$1,204,042.13	0.7%
50%	70,000	25,550,000	$1,670,757.27	$1,684,185.90	0.8%
70%	4,000	2,044,000	$136,795.29	$133,294.32	-2.6%
70%	5,000	2,555,000	$168,901.81	$165,697.22	-1.9%
70%	10,000	5,110,000	$329,434.41	$327,711.74	-0.5%
70%	20,000	10,220,000	$650,499.63	$651,740.78	0.2%
70%	40,000	20,440,000	$1,292,630.06	$1,299,798.86	0.6%
70%	50,000	25,550,000	$1,613,695.27	$1,623,827.90	0.6%
70%	70,000	35,770,000	$2,255,825.70	$2,271,885.97	0.7%
90%	4,000	2,628,000	$170,227.77	$166,877.18	-2.0%
90%	5,000	3,285,000	$210,692.41	$207,675.80	-1.4%
90%	10,000	6,570,000	$413,015.62	$411,668.89	-0.3%
90%	20,000	13,140,000	$817,662.04	$819,655.09	0.2%
90%	40,000	26,280,000	$1,626,954.87	$1,635,627.47	0.5%
90%	50,000	32,850,000	$2,031,601.29	$2,043,613.67	0.6%
90%	70,000	45,990,000	$2,840,894.13	$2,859,586.05	0.7%

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	$174,481.01	$172,328.06	-1.2%
80%	5,000	2,920,000	$211,621.16	$208,847.58	-1.3%
80%	10,000	5,840,000	$397,321.92	$391,445.15	-1.5%
80%	20,000	11,680,000	$768,723.44	$756,640.30	-1.6%
80%	40,000	23,360,000	$1,511,526.48	$1,487,030.61	-1.6%
80%	60,000	35,040,000	$2,254,329.52	$2,217,420.91	-1.6%
80%	80,000	46,720,000	$2,997,132.56	$2,947,811.22	-1.6%
90%	4,000	2,628,000	$191,052.88	$188,496.92	-1.3%
90%	5,000	3,285,000	$232,336.01	$229,058.65	-1.4%
90%	10,000	6,570,000	$438,751.61	$431,867.30	-1.6%
90%	20,000	13,140,000	$851,582.82	$837,484.59	-1.7%
90%	40,000	26,280,000	$1,677,245.24	$1,648,719.18	-1.7%
90%	60,000	39,420,000	$2,502,907.66	$2,459,953.78	-1.7%
90%	80,000	52,560,000	$3,328,570.08	$3,271,188.37	-1.7%

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2016 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	$507,088	$23,760	$1,474	($715)	$24,519	$16,232	$2,252	$18,484	$29,960	$33,036	$63,049	$63,804	$189,849
Schedule 15	$875	$91	$3	($2)	$92	$16	$4	$20	$62	$69	$136	$92	$359
Schedule 32	$99,407	$4,566	$290	($150)	$4,705	$2,910	$442	$3,352	$4,900	$5,403	$12,006	$13,605	$35,913
Schedule 38	$2,284	$140	$8	($4)	$144	$62	$10	$72	$253	$279	$756	$847	$2,134
Schedule 47	$1,528	$140	$4	($2)	$142	$40	$7	$47	$208	$230	$1,335	$1,147	$2,920
Schedule 49	$4,562	$363	$12	($6)	$369	$122	$20	$142	$632	$696	$4,219	$2,904	$8,451
Schedule 83													
Secondary	$170,653	$6,373	$496	($262)	$6,607	$5,087	$759	$5,846	$8,565	$9,444	$18,317	$10,525	$46,851
Schedule 85													
Secondary		$4,290	$416	($2,577)	$2,130								
Primary		$482	$52	($329)	$205								
Class Total	$134,610					$3,945	$603	$4,548	$7,795	$8,596	$14,338	$6,051	$36,780
Schedule 85 1-4 MW													
Secondary		$909	$88	($546)	$451								
Primary		$1,074	$115	($732)	$457								
Class Total	$54,394					$1,487	$236	$1,723	$3,165	$3,490	$5,933	$1,785	$14,372
Schedule 89 GT 4 MW													
Secondary		$5	$2	($15)	($8)						$112		$112
Primary		$1,628	$229	($1,489)	$368						$3,027		$3,027
Subtransmission		$240	$63	($418)	($115)						$911		$911
Class Total	$53,146					$1,353	$229	$1,583	$3,024	$4,250			$7,274
Schedule 90-P	$80,762	$2,382	$235	($1,611)	$1,005	$2,112	$367	$2,479	$3,088	$3,405	$1,418		$7,910
Schedules 91 & 95	$4,000	$341	$12	($7)	$346	$73	$18	$91	$285	$314	$620	$422	$1,642
Schedules 92	$178	$7	$1	($0)	$7	$4	$1	$5	$6	$6	$12	$5	$29
Totals	$1,113,488	$46,791	$3,499	($8,866)	$41,424	$33,444	$4,948	$38,392	$61,941	$69,217	$126,189	$101,188	$358,535

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2016 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	$92,850	$35	$7,371	$1	$5,675	$1	$53,490	$10	$37,455	$7	$196,842	$55		$196,897	$936,837
Schedule 15	$252		$61		$0		$140		$100		$553	$0	$1,706	$2,260	$3,606
Schedule 32	$8,921	$13,843	$200	$130	$909	$589	$3,263	$2,115	$4,042	$2,620	$17,335	$19,297		$36,632	$180,009
Schedule 38	$18	$402	$0	$0	$15	$110	$12	$86	$31	$230	$76	$827		$903	$5,538
Schedule 47	$21	$386	$0	$3	$3	$40	$16	$207	$16	$205	$56	$841		$897	$5,534
Schedule 49	$1	$354	$0	$4	$0	$31	$0	$96	$1	$295	$2	$779		$781	$14,306
Schedule 83															
Secondary	$329	$14,517	$4	$66	$55	$881	$60	$970	$255	$4,109	$703	$20,543		$21,246	$251,203
Schedule 85															
Secondary		$3,543		$48		$323		$283		$2,498	$0	$6,696		$6,696	
Primary		$516		$6		$37		$33		$290	$0	$882		$882	$185,851
Schedule 85 1-4 MW															
Secondary		$447		$3		$19		$17		$147	$0	$633		$633	
Primary		$280		$3		$19		$17		$149	$0	$468		$468	$72,499
Schedule 89 GT 4 MW															
Secondary		$18		$0		$0		$0		$13	$0	$32		$32	
Primary		$155		$0		$0		$5		$364	$0	$523		$523	
Subtransmission		$187		$0		$0		$1		$108	$0	$296		$296	$67,149
Schedule 90-P		$23		$0		$0		$0		$183	$0	$206		$206	$92,363
Schedules 91 & 95	$1,466			$0		$0	$244		$70		$1,780	$0	$5,592	$7,372	$13,450
Schedule 92		$18		$0		$0		$19		$3	$0	$40		$40	$259
Totals	$103,857	$34,727	$7,636	$263	$6,657	$2,051	$57,226	$3,859	$41,971	$11,221	$217,346	$52,120	$7,298	$276,765	$1,828,603

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2016

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	$196,842	748,270	Customers	$21.92	per cust. per mo.	$196,825
Three-Phase	$55	143	Customers	$32.24	per cust. per mo.	$55
Trans. & Rel. Serv. Charge	$18,484	7,620,805	MWh	2.43	mills/kWh	$18,519
Distribution Charge	$189,849	7,620,805	MWh	24.91	mills/kWh	$189,834
Franchise Fees & Other	$24,519	7,620,805	MWh	3.22	mills/kWh	$24,539
Energy Charge	$507,088	7,620,805	MWh	66.54	mills/kWh	$507,088
Subtotal	$936,837					$936,861
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		748,270	Customers	$11.00	per cust. per mo.	$98,772
Three-Phase		143	Customers	$11.00	per cust. per mo.	$19
Trans. & Rel. Serv. Charge		7,620,805	MWh	2.43	mills/kWh	$18,519
Distribution Charge		7,620,805	MWh	37.78	mills/kWh	$287,914
System Usage Charge Calculation						
Franchise Fees & Other		7,620,805	MWh	3.22	mills/kWh	$24,539
Cust Impact Offset		7,620,805	MWh	0.00	mills/kWh	$0
System Usage Charge		7,620,805	MWh	3.22	mills/kWh	$24,539
Energy Charge						
Block 1 (First 500 kWh)		4,015,082	MWh	65.22	mills/kWh	$261,864
Block 2 (501-1,000 kWh)		2,214,791	MWh	65.22	mills/kWh	$144,449
Block 3 (Over 1,000 kWh)		1,390,932	MWh	72.44	mills/kWh	$100,759
Subtotal						$936,834
					w/o CIO	$936,834
SCHEDULE 15						
Outdoor Area Lighting						
Allocations						
Functional Costs						
Basic Charge	$553	2,254	Customers	$20.45	per cust. per mo.	$553
Trans. & Rel. Serv. Charge	$20	16,308	MWh	1.22	mills/kWh	$20
Distribution Charge	$359	16,308	MWh	22.02	mills/kWh	$359
Franchise Fees & Other	$92	16,308	MWh	5.67	mills/kWh	$92
Energy Charge	$875	16,308	MWh	53.66	mills/kWh	$875
Fixed Charges	$1,706	16,308	MWh			$1,706
Subtotal	$3,606					$3,606
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		16,308	MWh	1.22	mills/kWh	$20
Distribution Charge		16,308	MWh	55.94	mills/kWh	$912
System Usage Charge Calc						
Franchise Fees & Other		16,308	MWh	5.67	mills/kWh	$92
Cust Impact Offset		16,308	MWh	(9.09)	mills/kWh	($148)
System Usage Charge		16,308	MWh	(3.42)	mills/kWh	($56)
Energy Charge		16,308	MWh	53.66	mills/kWh	$875
Fixed Charges		16,308	MWh			$1,706
Subtotal						$3,458
					w/o CIO	$3,606

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2016

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	$17,335	54,838	Customers	$26.34	per cust. per mo.	$17,333
Three-Phase	$19,297	35,546	Customers	$45.24	per cust. per mo.	$19,297
Trans. & Rel. Serv. Charge	$3,352	1,599,950	MWh	2.10	mills/kWh	$3,360
Distribution Charge	$35,913	1,599,950	MWh	22.45	mills/kWh	$35,919
Franchise Fees & Other	$4,705	1,599,950	MWh	2.94	mills/kWh	$4,704
Energy Charge	$99,407	1,599,950	MWh	62.13	mills/kWh	$99,405
Subtotal	$180,009					$180,018
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		54,838	Customers	$16.00	per cust. per mo.	$10,529
Three-Phase		35,546	Customers	$22.00	per cust. per mo.	$9,384
Trans. & Rel. Serv. Charge		1,599,950	MWh	2.10	mills/kWh	$3,360
Distribution Charge						
First 5 MWh		1,408,301	MWh	37.50	mills/kWh	$52,811
Over 5 MWh		191,649	MWh	7.00	mills/kWh	$1,342
System Usage Charge Calc						
Franchise Fees & Other		1,599,950	MWh	2.99	mills/kWh	$4,784
Cust Impact Offset		1,599,950	MWh	0.00	mills/kWh	$0
System Usage Charge		1,599,950	MWh	2.99	mills/kWh	$4,784
Energy Charge		1,599,950	MWh	62.27	mills/kWh	$99,629
Subtotal						$181,839
					w/o CIO	$181,839
SCHEDULE 38						
Time-of-Day G.S. >30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$76	66	Customers	$95.74	per cust. per mo.	$76
Three-Phase	$827	482	Customers	$143.04	per cust. per mo.	$827
Trans. & Rel. Serv. Charge	$72	39,036	MWh	1.84	per cust. per mo.	$72
Distribution Charges	$2,134	39,036	MWh	54.68	per cust. per mo.	$2,134
Franchise Fees & Other	$144	39,036	MWh	3.70	mills/kWh	$144
Energy Charge	$2,284	39,036	MWh	58.52	mills/kWh	$2,284
Subtotal	$5,538					$5,538
Pricing						
Functional Costs						
Basic						
Single-Phase		66	Customers	$25.00	per cust. per mo.	$20
Three-Phase		482	Customers	$25.00	per cust. per mo.	$145
Trans. & Rel. Serv. Charge		39,036	MWh	2.10	mills/kWh	$82
Distribution Charges		39,036	MWh	114.66	mills/kWh	$4,476
System Usage Charge						
Franchise Fees & Other		39,036	MWh	5.05	mills/kWh	$197
Cust Impact Offset		39,036	MWh	(44.45)	mills/kWh	($1,735)
System Usage Charge		39,036	MWh	(39.40)	mills/kWh	($1,538)
Energy Charge Calc						
On-Peak (special)		21,383	MWh	71.83	mills/kWh	$1,536
Off-Peak		17,653	MWh	61.83	mills/kWh	$1,091
Reactive Demand Charge		66,989	kVar	0.50	kVar	$33
Subtotal						$5,845
					w/o CIO	$7,580

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2016

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	$56	231	Customers	$40.74	per cust. per summ. mo.	$56
Three-Phase	$841	2,921	Customers	$47.97	per cust. per summ. mo.	$841
Trans. & Rel. Serv. Charge	$47	20,845	MWh	2.26	mills/kWh	$47
Distribution Charges	$2,920	20,845	MWh	140.07	mills/kWh	$2,920
Franchise Fees & Other	$142	20,845	MWh	6.82	mills/kWh	$142
Energy Charge	$1,528	20,845	MWh	73.29	mills/kWh	$1,528
Subtotal	$5,534					$5,534
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		231	Customers	$44.00	per cust. per summ. mo.	$61
Three-Phase		2,921	Customers	$44.00	per cust. per summ. mo.	$771
Trans. & Rel. Serv. Charge		20,845	MWh	2.10	mills/kWh	$44
Distribution Charge Calc						
First 50 kWh per kW		7,404	MWh	76.77	mills/kWh	$568
Over 50 kWh per kW		13,441	MWh	66.77	mills/kWh	$897
System Usage Charge Calc						
Franchise Fees & Other		20,845	MWh	2.99	mills/kWh	$62
Cust Impact Offset		20,845	MWh	0.00	mills/kWh	$0
System Usage Charge		20,845	MWh	2.99	mills/kWh	$62
Energy Charge		20,845	MWh	62.27	mills/kWh	$1,298
Reactive Demand Charge		76	kVar	$0.50	kVar	$0
Subtotal with Consumer Impact Offset						$3,702
					w/o CIO	$3,702
Sum of Schedules 32 & 47	$185,543				w/o CIO	$185,541
SCHEDULE 49						
Irrig. & Drain. Pump. - > 30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$2	3	Customers	$94.39	per cust. per summ. mo.	$2
Three-Phase	$779	1,346	Customers	$96.51	per cust. per summ. mo.	$779
Trans. & Rel. Serv. Charge	$142	62,677	MWh	2.27	mills/kWh	$142
Distribution Charges	$8,451	62,677	MWh	134.83	mills/kWh	$8,451
Franchise Fees & Other	$369	62,677	MWh	5.89	mills/kWh	$369
Energy Charge	$4,562	62,677	MWh	72.79	mills/kWh	$4,562
Subtotal	$14,306					$14,306
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		3	Customers	$50.00	per cust. per summ. mo.	$1
Three-Phase		1,346	Customers	$50.00	per cust. per summ. mo.	$404
Trans. & Rel. Serv. Charge		62,677	MWh	2.10	mills/kWh	$132
Distribution Charge Calc						
First 50 kWh per kW		20,023	MWh	121.46	mills/kWh	$2,432
Over 50 kWh per kW		42,655	MWh	111.46	mills/kWh	$4,754
System Usage Charge Calc						
Franchise Fees & Other		62,677	MWh	5.05	mills/kWh	$317
Cust Impact Offset		62,677	MWh	(55.19)	mills/kWh	($3,459)
System Usage Charge		62,677	MWh	(50.14)	mills/kWh	($3,143)
Energy Charge		62,677	MWh	67.31	mills/kWh	$4,219
Reactive Demand Charge		11,083	kVar	0.50	kVar	$6
Subtotal with Consumer Impact Offset						$8,804
					w/o CIO	$12,263
Sum of Schedules 38 & 49	$19,844				w/o CIO	$19,844

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2016

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	$703	645	Customers	$90.84	per cust, per mo.	$703
Three-Phase Secondary	$20,543	10,384	Customers	$164.86	per cust, per mo.	$20,543
Transmission & Related Service Charge	$5,846	8,414,140	kW demand	$0.69	per kW demand	$5,806
Distribution Charges						
Feeder Backbone	$18,317	10,339,799	kW faccap	$1.77	per kW faccap	$18,301
Feeder Local Facilities	$10,525	10,339,799	kW faccap	$1.02	per kW faccap	$10,547
Subtransmission Charge	$9,444	8,414,140	kW demand	$1.12	per kW demand	$9,424
Substation Charge	$8,565	8,414,140	kW demand	$1.02	per kW demand	$8,582
Secondary Franchise Fees & Other	$6,607	2,795,179	MWh	2.36	mills/kWh	$6,597
Secondary COS Energy Charge	$170,653	2,795,179	MWh	61.05	mills/kWh	$170,646
Subtotal	$251,203					$251,148
Pricing						
Functional Costs						
Basic Charge						
Secondary Single-Phase		645	Customers	$30.00	per cust, per mo.	$232
Secondary Three-Phase		10,384	Customers	$40.00	per cust, per mo.	$4,984
Trans. & Rel. Serv. Charge						
On-peak		8,404,396	kW demand	$0.79	per kW demand	$6,639
Off-peak		9,744	kW demand	$0.00	per kW demand	$0
Distribution Charges						
Secondary Facilities Charge						
First 30 kW		3,970,350	kW faccap	$2.85	<= 30 kW faccap	$11,315
Over 30 kW		6,369,449	kW faccap	$2.75	> 30 kW faccap	$17,516
Secondary Demand Charge						
On-peak		8,404,396	kW demand	$2.38	per kW demand	$20,002
Off-peak		9,744	kW demand	$0.00	per kW demand	$0
Secondary System Usage Charge Calc						
Franchise Fees & Other		2,795,179	MWh	2.36	mills/kWh	$6,597
Cust Impact Offset		2,795,179	MWh	1.73	mills/kWh	$4,836
Rate Design		2,795,179	MWh	4.65	mills/kWh	$12,998
System Usage Charge		2,795,179	MWh	8.74	mills/kWh	$24,430
COS Energy Charge						
On-peak		1,750,906	MWh	66.66	mills/kWh	$116,715
Off-peak		1,044,273	MWh	51.66	mills/kWh	$53,947
Reactive Demand Charge		501,656	kVar	$0.50	kVar	$251
Subtotal						$256,033
					w/o CIO	$251,197

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2016

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	$7,329	1,422	Customers	$429.57	per cust, per mo.	$7,328
Primary	$1,350	236	Customers	$476.61	per cust, per mo.	$1,350
Transmission & Related Service Charge	$6,271	8,180,057	kW on-peak	$0.77	per kW demand	$6,299
Distribution Charges						
Feeder Backbone	$20,271	11,383,574	kW faccap	$1.78	per kW faccap	$20,263
Feeder Local Facilities	$7,836	11,383,574	kW faccap	$0.69	per kW faccap	$7,855
Subtransmission Charge	$12,086	9,652,312	kW on-peak	$1.25	per kW on-peak demand	$12,065
Substation Charge	$10,960	9,652,312	kW on-peak	$1.14	per kW on-peak demand	$11,004
Secondary Franchise Fees & Other	$2,580	2,902,903	MWh	0.89	mills/kWh	$2,584
Primary Franchise Fees & Other	$662	986,738	MWh	0.67	mills/kWh	$661
COS Energy Charge	$189,005	3,177,726	MWh	59.48	mills/kWh	$189,011
Subtotal	$258,350					$258,420
Pricing						
Functional Costs						
Basic Charge						
Secondary		1,422	Customers	$430.00	per cust, per mo.	$7,336
Primary		236	Customers	$460.00	per cust, per mo.	$1,303
Secondary Trans. & Rel. Serv. Charge		6,415,768	kW on-peak	$0.79	per kW demand	$5,068
Primary Trans. & Rel. Serv. Charge		1,764,289	kW on-peak	$0.77	per kW demand	$1,359
Distribution Charges						
Secondary Facilities Charge						
First 200 kW		3,412,000	kW faccap	$3.01	per kW faccap	$10,270
Over 200 kW		5,178,238	kW faccap	$2.11	per kW faccap	$10,926
Primary Facilities Charge						
First 200 kW		566,600	kW faccap	$2.94	per kW faccap	$1,666
Over 200 kW		2,226,736	kW faccap	$2.04	per kW faccap	$4,543
Secondary Demand Charge		7,315,800	kW on-peak	$2.38	per kW demand	$17,412
Primary Demand Charge		2,336,512	kW on-peak	$2.32	per kW demand	$5,421
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		2,464,564	MWh	1.11	mills/kWh	$2,736
Cust Impact Offset		2,464,564	MWh	0.09	mills/kWh	$222
COS System Usage Charge		2,464,564	MWh	1.20	mills/kWh	$2,957
DA Franchise Fees & Other		438,339	MWh	(0.35)	mills/kWh	($152)
Cust Impact Offset		438,339	MWh	0.09	mills/kWh	$39
DA System Usage Charge		438,339	MWh	(0.26)	mills/kWh	($113)
Primary System Usage Charge Calc						
COS Franchise Fees & Other		713,162	MWh	1.07	mills/kWh	$763
Cust Impact Offset		713,162	MWh	0.09	mills/kWh	$64
COS System Usage Charge		713,162	MWh	1.16	mills/kWh	$827
DA Franchise Fees & Other		273,576	MWh	(0.36)	mills/kWh	($98)
Cust Impact Offset		273,576	MWh	0.09	mills/kWh	$25
DA System Usage Charge		273,576	MWh	(0.27)	mills/kWh	($73)
Secondary COS Energy Charge						
On-peak		1,617,793	MWh	64.97	mills/kWh	$105,108
Off-peak		846,771	MWh	49.97	mills/kWh	$42,313
Primary COS Energy Charge						
On-peak		448,156	MWh	63.87	mills/kWh	$28,624
Off-peak		265,006	MWh	48.87	mills/kWh	$12,951
Reactive Demand Charge		1,621,799	kVar	$0.50	kVar	$811
Subtotal						$258,708
					w/o CIO	$258,358

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2016

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	$32	1	Customers	$2,672.65	per cust, per mo.	$32
Primary Basic Charge	$523	27	Customers	$1,615.63	per cust, per mo.	$523
Subtransmission Basic Charge	$296	8	Customers	$3,086.65	per cust, per mo.	$296
Transmission & Related Service Charge	$1,583	1,887,983	kW on-peak	$0.84	per kW on-peak demand	$1,586
Distribution Charges						
Feeder Backbone	$4,050	4,557,428	kW faccap	$0.89	per kW faccap	$4,056
Feeder Local Facilities						$0
Subtransmission Demand Charge	$4,250	3,321,903	kW on-peak	$1.28	per kW on-peak demand	$4,252
Substation Demand Charge	$3,024	2,524,913	kW on-peak	$1.20	per kW on-peak demand	$3,030
Secondary Franchise Fees & Other	($8)	14,393	MWh	(0.57)	mills/kWh	($8)
Primary Franchise Fees & Other	$368	1,384,519	MWh	0.27	mills/kWh	$374
Subtransmission Franchise Fees & Other	($115)	542,815	MWh	(0.21)	mills/kWh	($114)
Energy Charge	$53,146	934,442	MWh	56.87	mills/kWh	$53,142
Subtotal	$67,149					$67,169
Pricing						
Functional Costs						
Secondary Basic Charge		1	Customers	$2,670.00	per cust, per mo.	$32
Primary Basic Charge		27	Customers	$1,620.00	per cust, per mo.	$525
Subtransmission Basic Charge		8	Customers	$3,090.00	per cust, per mo.	$297
Secondary Trans. & Rel. Serv. Charge		0	kW on-peak	$0.79	per kW on-peak demand	$0
Primary Trans. & Rel. Serv. Charge		1,605,117	kW on-peak	$0.77	per kW on-peak demand	$1,236
Subtransmission Trans. & Rel. Serv. Charge		282,866	kW on-peak	$0.76	per kW on-peak demand	$215
Distribution Charges						
Secondary Facilities Charge						
First 1,000 kW		12,000	kW faccap	$0.99	per kW faccap	$12
1,001-4,000 kW		36,000	kW faccap	$0.99	per kW faccap	$36
Greater than 4,000 kW		49,536	kW faccap	$0.99	per kW faccap	$49
Primary Facilities Charge						
First 1,000 kW		324,000	kW faccap	$0.96	per kW faccap	$311
1,001-4,000 kW		972,000	kW faccap	$0.96	per kW faccap	$933
Greater than 4,000 kW		1,411,040	kW faccap	$0.96	per kW faccap	$1,354
Subtransmission Facilities Charge						
First 1,000 kW		96,000	kW faccap	$0.96	per kW faccap	$92
1,001-4,000 kW		288,000	kW faccap	$0.96	per kW faccap	$276
Greater than 4,000 kW		1,368,852	kW faccap	$0.96	per kW faccap	$1,313
Secondary Demand Charge		41,683	kW on-peak	$2.38	per kW on-peak demand	$99
Primary Demand Charge		2,483,230	kW on-peak	$2.32	per kW on-peak demand	$5,761
Subtransmission Demand Charge		796,990	kW on-peak	$1.21	per kW on-peak demand	$964
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		0	MWh	0.83	mills/kWh	$0
Cust Impact Offset		0	MWh	0.00	mills/kWh	$0
COS System Usage Charge		0	MWh	0.83	mills/kWh	$0
DA Franchise Fees & Other		14,393	MWh	(0.58)	mills/kWh	($8)
Cust Impact Offset		14,393	MWh	0.00	mills/kWh	$0
DA System Usage Charge		14,393	MWh	(0.58)	mills/kWh	($8)
Primary System Usage Charge Calc						
COS Franchise Fees & Other		851,370	MWh	0.80	mills/kWh	$681
Cust Impact Offset		851,370	MWh	0.00	mills/kWh	$0
COS System Usage Charge		851,370	MWh	0.80	mills/kWh	$681
DA Franchise Fees & Other		533,149	MWh	(0.58)	mills/kWh	($308)
Cust Impact Offset		533,149	MWh	0.00	mills/kWh	$0
DA System Usage Charge		533,149	MWh	(0.58)	mills/kWh	($308)
Subtransmission System Usage Charge Calc						
COS Franchise Fees & Other		83,072	MWh	0.77	mills/kWh	$64
Cust Impact Offset		83,072	MWh	0.00	mills/kWh	$0
COS System Usage Charge		83,072	MWh	0.77	mills/kWh	$64
DA Franchise Fees & Other		305,980	MWh	(0.59)	mills/kWh	($179)
Cust Impact Offset		305,980	MWh	0.00	mills/kWh	$0
DA System Usage Charge		305,980	MWh	(0.59)	mills/kWh	($179)
Secondary Energy Charge						
On-peak		0	MWh	64.09	mills/kWh	$0
Off-peak		0	MWh	49.09	mills/kWh	$0
Primary Energy Charge						
On-peak		501,367	MWh	63.04	mills/kWh	$31,606
Off-peak		350,003	MWh	48.04	mills/kWh	$16,814
Subtransmission Energy Charge						
On-peak		53,253	MWh	62.25	mills/kWh	$3,315
Off-peak		29,819	MWh	47.25	mills/kWh	$1,409
Reactive Demand Charge		496,281	kVar	$0.50	kVar	$248
Subtotal						$67,147
					w/o CIO	$67,147

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2016

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	$206	4	Customers	$4,301.96	per cust, per mo.	$206
Transmission & Related Service Charge	$2,479	2,259,447	kW on-peak	$1.10	per kW on-peak demand	$2,485
Distribution Charges						
Feeder Backbone	$1,418	2,427,621	kW faccap	$0.58	per kW faccap	$1,408
Subtransmission Demand Charge	$3,405	2,259,447	kW on-peak	$1.51	per kW on-peak demand	$3,412
Substation Demand Charge	$3,088	2,259,447	kW on-peak	$1.37	per kW on-peak demand	$3,095
Primary Franchise Fees & Other	$1,005	1,498,007	MWh	0.67	mills/kWh	$1,004
Energy Charge	$80,762	1,498,007	MWh	53.91	mills/kWh	$80,758
Subtotal	$92,363					$92,368
Pricing						
Functional Costs						
Primary Basic Charge		4	Customers	$25,000.00	per cust, per mo.	$1,200
Primary Trans. & Rel. Serv. Charge		2,259,447	kW on-peak	$0.77	per kW on-peak demand	$1,740
Distribution Charges						
Primary Facilities Charge		2,427,621	kW faccap	$0.97	per kW faccap	$2,355
Primary Demand Charge		2,259,447	kW on-peak	$2.32	per kW on-peak demand	$5,242
Primary System Usage Charge Calc						
COS Franchise Fees & Other		1,498,007	MWh	0.67	mills/kWh	$1,004
Cust Impact Offset		1,498,007	MWh	0.00	mills/kWh	$0
COS System Usage Charge		1,498,007	MWh	0.67	mills/kWh	$1,004
Primary Energy Charge						
On-peak		862,951	MWh	60.27	mills/kWh	$52,010
Off-peak		635,057	MWh	45.27	mills/kWh	$28,749
Reactive Demand Charge		120,047	kVar	$0.50	kVar	$60
						$92,359
					w/o CIO	$92,359

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2016

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULES 91 & 95						
Street & Highway Lighting						
Allocations						
Functional Costs						
Basic Charge	$1,780	205	Customers	$723.48	per cust, per mo.	$1,780
Trans. & Rel. Serv. Charge	$91	74,544	MWh	1.22	mills/kWh	$91
Distribution Charge	$1,642	74,544	MWh	22.02	mills/kWh	$1,641
Franchise Fees & Other	$346	74,544	MWh	4.64	mills/kWh	$346
COS Energy Charge	$4,000	74,544	MWh	53.66	mills/kWh	$4,000
Fixed Charges	$5,592					$5,592
Subtotal	$13,450					$13,450
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		74,544	MWh	1.22	mills/kWh	$91
Distribution Charge		74,544	MWh	45.89	mills/kWh	$3,421
System Usage Charge Calc						
Franchise Fees & Other		74,544	MWh	4.64	mills/kWh	$346
Cust Impact Offset		74,544	MWh	1.99	mills/kWh	$148
System Usage Charge		74,544	MWh	6.63	mills/kWh	$494
COS Energy Charge		74,544	MWh	53.66	mills/kWh	$4,000
Fixed Charges		74,544	MWh			$5,592
Subtotal						$13,598
					w/o CIO	$13,450
SCHEDULE 92						
Traffic Signals						
Allocations						
Functional Costs						
Basic Charge	$40	17	Customers	$196.67	per cust, per mo.	$40
Trans. & Rel. Serv. Charge	$5	3,243	MWh	1.61	mills/kWh	$5
Distribution Charge	$29	3,243	MWh	8.96	mills/kWh	$29
Franchise Fees & Other	$7	3,243	MWh	2.09	mills/kWh	$7
COS Energy Charge	$178	3,243	MWh	54.84	mills/kWh	$178
Subtotal	$259					$259
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		3,243	MWh	1.61	mills/kWh	$5
Distribution Charge		3,243	MWh	21.33	mills/kWh	$69
System Usage Charge Calc						
Franchise Fees & Other		3,243	MWh	2.09	mills/kWh	$7
Cust Impact Offset		3,243	MWh	0.00	mills/kWh	$0
System Usage Charge		3,243	MWh	2.09	mills/kWh	$7
COS Energy Charge		3,243	MWh	54.84	mills/kWh	$178
Subtotal						$259
					w/o CIO	$259

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at 2015 Prices ($000)	2016 Allocated Costs ($000)	Percent Change	Maximum Change	Impact Offset Cap	Cap Impact Offset MWH	Spread Offset Net Cap	CIO mills/kWh	CIO Revenues
Schedule 7	7,620,805	$913,144	$936,837	2.6%	12.0%					
Schedule 15	16,308	$3,628	$3,606	-0.6%	12.0%				(9.09)	($148)
Schedule 32	1,599,950	$175,073	$180,009	2.8%	12.0%					
Schedule 38	39,036	$5,251	$7,616	45.0%	12.0%	($1,735)	(39,036)		(44.45)	($1,735)
Schedule 47	20,845	$3,692	$5,534	49.9%	12.0%					
Schedule 49	62,677	$7,829	$12,228	56.2%	12.0%	($3,459)	(62,677)		(55.19)	($3,459)
Schedule 83	2,795,179	$248,442	$251,203	1.1%	12.0%	$0	0	$4,831	1.73	$4,836
Schedule 85	3,177,726	$262,216.47	$263,705.79	0.6%	12.0%	$0	0	$297	0.09	$286
Schedule 89	934,442	$73,401.89	$70,658.99	-3.7%	12.0%					
Schedule 90	1,498,007	$91,891	$92,363	0.5%	12.0%					
Schedules 91 & 95	74,544	$14,055	$13,450	-4.3%	12.0%				1.99	$148
Schedule 92	3,243	$251	$259	3.3%	12.0%					
COS TOTALS	17,842,764									
Sch 485 Energy	711,915							$67	0.09	$64
Sch 489 Energy	853,521									
Totals	19,408,200	$1,798,875	$1,837,469	2.1%		($5,194)	(101,713)	$5,194		($8)

Cap on Rate Change	12.0%
Cap on CIO (mills/kWh)	(100.00)

Note: does not include Sch 76R
Note: does not include employee discount

Schedule 83 CIO Percent	93%
Scheduel 85 CIO Percent	7%

PORTLAND GENERAL ELECTRIC
2016 Test Period Functionalized Revenue Requirement

Function	Amount	Spread
PRODUCTION	$1,114,003	$1,114,003
TRANSMISSION	$33,612	$33,612
ANCILLARY	$4,950	$4,950
DISTRIBUTION	$562,163	$562,163
METERING	$8,711	$8,711
BILLING	$61,108	$61,108
CONSUMER	$53,213	$53,213
TOTALS	$1,837,762	$1,837,762
Schedule 129		($8,866)
Employee Discount		$902
Partial Requirements Transmission		($153)
Partial Requirements Distribution		($239)
Spread Total		$1,829,405

Note: Employee discount is allocated to distribution

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2016 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$557,108	$556,850
Net Variable Power Costs	$556,895	$556,638
Production Costs	$1,114,003	$1,113,488
Ancillary Services	$4,950	$4,948
Transmission		
Transmission	$33,612	
Partial Requirements Daily Demand	($153)	
Transmission Costs	$33,459	$33,444
Distribution Services	$562,163	
Franchise	($46,809)	
Uncollectibles	($7,902)	
Trojan Decommissioning	($3,500)	
Partial Requirements Daily Demand	($239)	
Employee Discount	$902	$902
Distribution Costs	$504,614	$504,416
Consumer Services		
Metering Services	$8,711	$8,708
Billing Services	$61,108	$61,084
Other Consumer Services	$53,213	$53,192
Franchise Fees	$46,809	$46,791
Uncollectibles	$7,902	$7,899
Trojan Decommissioning	$3,500	$3,499
Schedule 129	($8,866)	($8,866)
Totals	$1,829,405	$1,828,603
Net of employee discount	$1,828,503	$1,827,701
Net of Sch 129	$1,837,370	$1,836,567
Calendar MWH (COS & ESS)	19,415,809	
Cycle MWH (COS & ESS)	19,408,200	
Cycle/Cal Ratio	99.96%	
COS Calendar Energy MWH	17,851,036	
COS Cycle MWH	17,842,764	
Cycle/Cal Ratio	99.95%	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF GENERATION REVENUE REQUIREMENT TO COS CUSTOMERS
2016

Schedules	COS Calendar Energy	Marginal Energy Costs ($000)	Generation Capacity Allocation	Marginal Capacity Costs ($000)	Marginal Capacity & Energy Costs ($000)	Capacity & Energy Allocation Percent	Allocated Capacity & Energy Costs ($000)	Cycle Basis Costs ($000)
Schedule 7	7,619,638	$401,864	50.73%	$217,019	$618,883	45.51%	$507,010	$507,088
Schedule 15	16,308	$792	0.06%	$276	$1,068	0.08%	$875	$875
Schedule 32	1,602,033	$83,982	8.77%	$37,516	$121,499	8.93%	$99,536	$99,407
Schedule 38	39,222	$2,105	0.16%	$697	$2,802	0.21%	$2,295	$2,284
Schedule 47	20,716	$1,116	0.17%	$738	$1,853	0.14%	$1,518	$1,528
Schedule 49	62,812	$3,269	0.54%	$2,312	$5,581	0.41%	$4,572	$4,562
Schedule 83	2,800,415	$146,402	14.56%	$62,296	$208,698	15.35%	$170,973	$170,653
Schedule 85	2,261,238	$118,431	11.05%	$47,255	$165,686	12.18%	$135,736	$134,610
Schedule 85 1-4 MW	914,212	$47,282	4.12%	$17,622	$64,904	4.77%	$53,171	$54,394
Schedule 89 GT 4 MW	932,806	$47,133	3.70%	$15,812	$62,944	4.63%	$51,566	$51,657
Schedule 90	1,503,848	$75,882	5.82%	$24,910	$100,792	7.41%	$82,572	$82,251
Schedule 91/95	74,544	$3,621	0.29%	$1,262	$4,883	0.36%	$4,000	$4,000
Schedule 92	3,243	$166	0.01%	$51	$217	0.02%	$178	$178
TOTAL	17,851,036	$932,045	100.0%	$427,765	$1,359,810	100.00%	$1,114,003	$1,113,488
Simple Cycle Proxy Plant $/kW				$127.44		TARGET	$1,114,003	
Projected Peak Load				3,357				
Marginal Capacity Costs ($000)				$427,765				

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT
2016

Schedules	Transmission Allocation Percent	Class Revenue Requirement
Schedule 7	48.53%	$16,232
Schedule 15	0.05%	$16
Schedule 32	8.70%	$2,910
Schedule 38	0.18%	$62
Schedule 47	0.12%	$40
Schedule 49	0.36%	$122
Schedule 83	15.21%	$5,087
Schedule 85	11.80%	$3,945
Schedule 85 1-4 MW	4.45%	$1,487
Schedule 89 GT 4 MW	4.05%	$1,353
Schedule 90-P	6.32%	$2,112
Schedules 91/95	0.22%	$73
Schedule 92	0.01%	$4
Target	100.00%	$33,444

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE REVENUE REQUIREMENT
2016

Schedules	Production Allocation Percent	Class Revenue Requirement
Schedule 7	45.51%	$2,252
Schedule 15	0.08%	$4
Schedule 32	8.93%	$442
Schedule 38	0.21%	$10
Schedule 47	0.14%	$7
Schedule 49	0.41%	$20
Schedule 83	15.35%	$759
Schedule 85	12.18%	$603
Schedule 85 1-4 MW	4.77%	$236
Schedule 89 GT 4 MW	4.63%	$229
Schedule 90-P	7.41%	$367
Schedules 91/95	0.36%	$18
Schedule 92	0.02%	$1
TOTAL	100.00%	$4,948
	TARGET	$4,948

PORTLAND GENERAL ELECTRIC
Applicable 2016 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	2,991	$149.89	$448,260
	SCHEDULE 2 - REACTIVE SUPPLY & VOLTAGE CONTROL		$/kW year	
2	12 CP kW Average	2,990,592	$0.461	$1,378,663
	SCHEDULE 3 - REGULATION & FREQUENCY RESPONSE		$/kW month	
3	Billing Determinant: Sum of Monthly Average 12 CP KW Charge: $6.695 per kW per month x .013	35,887,100	$0.09	$3,123,434
4		**ANCILLARY SERVICES TOTAL**		$4,950,356

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2016

Schedules	Cycle Generation Revenues	Allocation Percent	Class Revenue Requirement
Schedule 7	$507,223,878	42.13%	$1,474
Schedule 15	$875,087	0.07%	$3
Schedule 32	$99,676,905	8.28%	$290
Schedule 38	$2,627,411	0.22%	$8
Schedule 47	$1,298,635	0.11%	$4
Schedule 49	$4,218,822	0.35%	$12
Schedule 83	$170,662,566	14.18%	$496
Schedule 85-S	$143,204,469	11.89%	$416
Schedule 85-S 1-4 MW	$30,247,361	2.51%	$88
Schedule 89-S GT 4 MW	$844,392	0.07%	$2
Schedule 85-P	$17,866,084	1.48%	$52
Schedule 85-P 1-4 MW	$39,669,070	3.30%	$115
Schedule 89-P GT 4 MW	$78,738,429	6.54%	$229
Schedule 89-T	$21,820,578	1.81%	$63
Schedule 90-P	$80,759,055	6.71%	$235
Schedule 91/95	$4,000,053	0.33%	$12
Schedule 92	$177,840	0.01%	$1
TOTAL	$1,203,910,636		$3,499
		TARGET	$3,499

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2016

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	$388,220	$18,484	$507,088		$913,792	$10,094	$481	$13,185		$23,760
Schedule 15	$2,621	$20	$875		$3,516	$68	$1	$23		$91
Schedule 32	$72,835	$3,352	$99,407		$175,594	$1,894	$87	$2,585		$4,566
Schedule 38	$3,045	$72	$2,284		$5,401	$79	$2	$59		$140
Schedule 47	$3,821	$47	$1,528		$5,395	$99	$1	$40		$140
Schedule 49	$9,244	$142	$4,562		$13,949	$240	$4	$119		$363
Schedule 83-S	$68,593	$5,846	$170,653		$245,092	$1,784	$152	$4,437		$6,373
Schedule 85 201-4,000 kW	$60,503	$6,271	$189,005	$5,356	$261,134	$1,573	$163	$4,914	$105	$6,755
Schedule 89 GT 4 MW	$12,471	$1,583	$53,146	$3,510	$70,709	$324	$41	$1,382	$126	$1,873
Schedule 90-P	$8,351	$2,479	$80,762		$91,593	$217	$64	$2,100		$2,382
Schedules 91/95	$9,025	$91	$4,000		$13,116	$235	$2	$104		$341
Schedule 92	$70	$5	$178		$253	$2	$0	$5		$7
TOTALS	$638,799	$38,392	$1,113,488	$8,866	$1,799,544	$16,610	$998	$28,952	$231	$46,791

Franchise Fee Revenue Requirement **$46,791**

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
Schedule 7	7,620,805	1.32	7,620,805	0.06	7,620,805	1.73	0		3.12	
Schedule 15	16,308	4.18	16,308	0.03	16,308	1.40	0		5.61	4.18
Schedule 32	1,599,950	1.18	1,599,950	0.05	1,599,950	1.62	0		2.85	1.18
Schedule 38	39,036	2.03	39,036	0.05	39,036	1.52	0		3.60	2.03
Schedule 47	20,845	4.77	20,845	0.06	20,845	1.91	0		6.73	
Schedule 49	62,677	3.83	62,677	0.06	62,677	1.89	0		5.79	3.83
Schedule 83-S	2,795,179	0.64	2,795,179	0.05	2,795,179	1.59	0		2.28	0.64
Schedule 85-S 201-4,000 kW	2,902,903	0.41	2,464,564	0.05	2,464,564	1.55	438,339	0.15	2.01	0.55
Schedule 89-S GT 4 MW	14,393	0.19	0	0.04	0	1.51	14,393	0.15	1.74	0.33
Schedule 85-P 201-4,000 kW	986,738	0.40	713,162	0.05	713,162	1.52	273,576	0.15	1.97	0.55
Schedule 89-P GT 4 MW	1,384,519	0.18	851,370	0.04	851,370	1.48	533,149	0.15	1.71	0.33
Schedule 89-T	389,052	0.18	83,072	0.04	83,072	1.46	305,980	0.15	1.68	0.33
Schedule 90-P	1,498,007	0.14	1,498,007	0.04	1,498,007	1.40			1.59	0.14
Schedule 91/95	74,544	3.15	74,544	0.03	74,544	1.40	0		4.57	3.15
Schedule 92	3,243	0.56	3,243	0.04	3,243	1.43	0		2.03	0.56
TOTALS	19,408,200		17,842,764		17,842,764		1,565,436			

Revenues

Schedules	MWh	Fran. Fee mills/kWh	Fran. Fee Revenues
Schedule 7	7,620,805	3.12	$23,760
Schedule 15	16,308	5.61	$91
Schedule 32	1,599,950	2.85	$4,566
Schedule 38	39,036	3.60	$140
Schedule 47	20,845	6.73	$140
Schedule 49	62,677	5.79	$363
Schedule 83-S	2,795,179	2.28	$6,373
Schedule 85-S 201-4,000 kW	2,464,564	2.01	$4,956
Schedule 485-S 201-4,000 kW	438,339	0.55	$243
Schedule 89-S GT 4 MW	0	1.74	$0
Schedule 489-S GT 4 MW	14,393	0.33	$5
Schedule 85-P 201-4,000 kW	713,162	1.97	$1,407
Schedule 485-P 201-4,000 kW	273,576	0.55	$149
Schedule 89-P GT 4 MW	851,370	1.71	$1,453
Schedule 489-P GT 4 MW	533,149	0.33	$175
Schedule 89-T	83,072	1.68	$140
Schedule 489-T	305,980	0.33	$100
Schedule 90-P	1,498,007	1.59	$2,382
Schedule 91/95	74,544	4.57	$341
Schedule 92	3,243	2.03	$7
TOTALS	19,408,200		$46,791

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2016

Schedules	Cycle Energy	Percent	Allocations ($000)
Schedule 85-S	2,395,416	33.4%	($2,352)
Schedule 85-S 1-4 MW	507,487	7.1%	($498)
Schedule 89-S GT 4 MW	14,393	0.2%	($14)
Schedule 85-P	305,855	4.3%	($300)
Schedule 85-P 1-4 MW	680,883	9.5%	($669)
Schedule 89-P GT 4 MW	1,384,519	19.3%	($1,359)
Schedule 90-P	1,498,007	20.9%	($1,471)
Schedule 89-T	389,052	5.4%	($382)
TOTAL	7,175,612	100.00%	($7,046)
		TARGET	($7,046)

ALLOCATION OF TRANSITION ADJUSTMENT FOR POST 2013 VINTAGE CUSTOMERS

Schedules	Cycle Energy	Percent	Allocations ($000)
Schedule 7	7,620,805	39.3%	($715)
Schedule 15	16,308	0.1%	($2)
Schedule 32	1,599,950	8.2%	($150)
Schedule 38	39,036	0.2%	($4)
Schedule 47	20,845	0.1%	($2)
Schedule 49	62,677	0.3%	($6)
Schedule 83	2,795,179	14.4%	($262)
Schedule 85-S	2,395,416	12.3%	($225)
Schedule 85-S 1-4 MW	507,487	2.6%	($48)
Schedule 89-S GT 4 MW	14,393	0.1%	($1)
Schedule 85-P	305,855	1.6%	($29)
Schedule 85-P 1-4 MW	680,883	3.5%	($64)
Schedule 89 GT 4 MW	1,384,519	7.1%	($130)
Schedule 89-T	389,052	2.0%	($36)
Schedule 90-P	1,498,007	7.7%	($141)
Schedules 91/95	74,544	0.4%	($7)
Schedule 92	3,243	0.0%	($0)
TOTAL	19,408,200	100.00%	($1,820)
		TARGET	($1,820)

Note: does not include partial requirements customers

PORTLAND GENERAL ELECTRIC
ALLOCATION OF UNCOLLECTIBLES
2016

Grouping	Marginal Cost Allocation Percent	Class Revenue Requirement
Schedule 7		
Single Phase	93.32%	$7,371
Three Phase	0.02%	$1
Schedule 15		
Residential	0.30%	$24
Commercial	0.47%	$37
Schedule 32		
Single Phase	2.53%	$200
Three Phase	1.64%	$130
Schedule 38		
Single Phase	0.00%	$0
Three Phase	0.00%	$0
Schedule 47		
Single Phase	0.00%	$0
Three Phase	0.03%	$3
Schedule 49		
Single Phase	0.00%	$0
Three Phase	0.05%	$4
Schedule 83		
Single Phase	0.05%	$4
Three Phase	0.83%	$66
Schedule 85		
Secondary	0.61%	$48
Primary	0.07%	$6
Schedule 85 1-4 MW		
Secondary	0.04%	$3
Primary	0.04%	$3
Schedule 89 GT 4 MW		
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%	$7,899
	TARGET	$7,899

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2016

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	748,270	Customers	$20.22	$15,130	$19,930
		Three-Phase Customers	143	Customers	$57.47	$8	$11
	Service Design & Transformer						
		Single-Phase Customers	748,270	Customers	$73.98	$55,357	$72,919
		Three-Phase Customers	143	Customers	$130.73	$19	$25
FACILITIES	Feeder Backbone						
		Single-Phase Customers	1,996,443	kW, rateclass peak	$23.97	$47,855	$63,037
		Three-Phase Customers	382	kW, rateclass peak	$23.97	$9	$12
	Feeder Local Facilities						
		Single-Phase Customers	2,993,080	Design Demand	$16.18	$48,428	$63,792
		Three-Phase Customers	573	Design Demand	$16.18	$9	$12
DEMAND	Subtransmission		2,025,779	kW, rateclass peak	$12.38	$25,079	$33,036
	Substation		1,996,825	kW, rateclass peak	$11.39	$22,744	$29,960
SUBTOTAL						$214,638	$282,734
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		9,464	Lights	$3.88	$37	$48
	Service Design & Transformer		9,464	Lights	$5.44	$51	$68
FACILITIES	Feeder Backbone		952	kW, rateclass peak	$24.76	$24	$31
	Feeder Local Facilities		952	Design Demand	$16.86	$16	$21
DEMAND	Subtransmission		965	kW, rateclass peak	$12.38	$12	$16
	Substation		952	kW, rateclass peak	$11.39	$11	$14
FIXED	Luminaires & Poles						$390
SUBTOTAL						$151	$589
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		11,053	Lights	$3.88	$43	$57
	Service Design & Transformer		11,053	Lights	$5.44	$60	$79
FACILITIES	Feeeder Backbone		3,206	kW, rateclass peak	$24.76	$79	$105
	Feeder Local Facilities		3,206	Design Demand	$16.86	$54	$71
DEMAND	Subtransmission		3,253	kW, rateclass peak	$12.38	$40	$53
	Substation		3,206	kW, rateclass peak	$11.39	$37	$48
FIXED	Luminaires & Poles						$1,316
SUBTOTAL						$313	$1,729
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$105
	Service Design & Transformer						$147
FACILITIES	Feeeder Backbone						$136
	Feeder Local Facilities						$92
DEMAND	Subtransmission						$69
	Substation						$62
FIXED	Luminaires & Poles						$1,706
SUBTOTAL							$2,317

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2016

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	54,838	Customers	$18.32	$1,005	$1,323
		Three-Phase Customers	35,546	Customers	$70.94	$2,522	$3,322
	Service Design & Transformer						
		Single-Phase Customers	54,838	Customers	$105.18	$5,768	$7,598
		Three-Phase Customers	35,546	Customers	$224.71	$7,988	$10,522
FACILITIES	Feeder Backbone						
		Single-Phase Customers	129,376	kW, rateclass peak	$27.91	$3,611	$4,756
		Three-Phase Customers	197,185	kW, rateclass peak	$27.91	$5,503	$7,249
	Feeder Local Facilities						
		Single-Phase Customers	274,188	Design Demand	$23.61	$6,474	$8,527
		Three-Phase Customers	408,783	Design Demand	$9.43	$3,855	$5,078
DEMAND	Subtransmission		331,297	kW, rateclass peak	$12.38	$4,101	$5,403
	Substation		326,561	kW, rateclass peak	$11.39	$3,720	$4,900
SUBTOTAL						$44,545	$58,678
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	66	Customers	$52.41	$3	$5
		Three-Phase Customers	482	Customers	$125.41	$60	$80
	Service Design & Transformer						
		Single-Phase Customers	66	Customers	$149.42	$10	$13
		Three-Phase Customers	482	Customers	$507.27	$245	$322
FACILITIES	Feeder Backbone						
		Single-Phase Customers	653	kW, rateclass peak	$34.05	$22	$29
		Three-Phase Customers	16,196	kW, rateclass peak	$34.05	$551	$726
	Feeder Local Facilities						
		Single-Phase Customers	2,303	Design Demand	$19.37	$45	$59
		Three-Phase Customers	44,496	Design Demand	$13.45	$598	$788
DEMAND	Subtransmission		17,094	kW, rateclass peak	$12.38	$212	$279
	Substation		16,849	kW, rateclass peak	$11.39	$192	$253
SUBTOTAL						$1,939	$2,554
Schedule 47 Irrigation & Drainage Service - < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	231	Customers	$57.42	$13	$17
		Three-Phase Customers	2,921	Customers	$81.34	$238	$313
	Service Design & Transformer						
		Single-Phase Customers	231	Customers	$10.05	$2	$3
		Three-Phase Customers	2,921	Customers	$19.03	$56	$73
FACILITIES	Feeder Backbone						
		Single-Phase Customers	557	kW, rateclass peak	$73.00	$41	$54
		Three-Phase Customers	13,325	kW, rateclass peak	$73.00	$973	$1,281
	Feeder Local Facilities						
		Single-Phase Customers	2,310	Design Demand	$49.64	$115	$151
		Three-Phase Customers	29,210	Design Demand	$25.88	$756	$996
DEMAND	Subtransmission		14,083	kW, rateclass peak	$12.38	$174	$230
	Substation		13,882	kW, rateclass peak	$11.39	$158	$208
SUBTOTAL						$2,525	$3,326

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2016

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	3	Customers	$59.88	$0	$0
		Three-Phase Customers	1,346	Customers	$69.56	$94	$123
	Service Design & Transformer						
		Single-Phase Customers	3	Customers	$130.10	$0	$1
		Three-Phase Customers	1,346	Customers	$130.10	$175	$231
FACILITIES	Feeder Backbone						
		Single-Phase Customers	94	kW, rateclass peak	$76.09	$7	$9
		Three-Phase Customers	41,996	kW, rateclass peak	$76.09	$3,196	$4,209
	Feeder Local Facilities						
		Single-Phase Customers	188	Design Demand	$32.76	$6	$8
		Three-Phase Customers	84,394	Design Demand	$26.05	$2,198	$2,896
DEMAND	Subtransmission		42,701	kW, rateclass peak	$12.38	$529	$696
	Substation		42,090	kW, rateclass peak	$11.39	$479	$632
SUBTOTAL						$6,685	$8,805
Schedule 83 General Service (31-200 kW)							
CUSTOMER	Meters						
		Single-Phase Customers	645	Customers	$52.33	$34	$44
		Three-Phase Customers	10,384	Customers	$124.16	$1,289	$1,698
	Service Design & Transformer						
		Single-Phase Customers	645	Customers	$334.66	$216	$284
		Three-Phase Customers	10,384	Customers	$937.19	$9,732	$12,819
FACILITIES	Feeder Backbone						
		Single-Phase Customers	16,303	kW, rateclass peak	$24.36	$397	$523
		Three-Phase Customers	554,539	kW, rateclass peak	$24.36	$13,509	$17,794
	Feeder Local Facilities						
		Single-Phase Customers	24,633	Design Demand	$19.94	$491	$647
		Three-Phase Customers	836,944	Design Demand	$8.96	$7,499	$9,878
DEMAND	Subtransmission		579,119	kW, rateclass peak	$12.38	$7,169	$9,444
	Substation		570,842	kW, rateclass peak	$11.39	$6,502	$8,565
SUBTOTAL						$46,838	$61,697
Schedule 85 General Service (201-1,000 kW)							
CUSTOMER	Meters						
		Secondary Customers	1,343	Customers	$163.10	$219	$288
		Primary Customers	156	Customers	$1,781.36	$278	$366
	Service Design & Transformer						
		Secondary Customers	1,343	Customers	$1,840.38	$2,471	$3,255
		Primary Customers	156	Customers	$727.30	$114	$150
FACILITIES	Feeder Backbone		519,565	kW, rateclass peak	$20.95	$10,885	$14,338
	Feeder Local Facilities		671,590	Design Demand	$6.84	$4,594	$6,051
DEMAND	Subtransmission		527,099	kW, rateclass peak	$12.38	$6,525	$8,596
	Substation		519,565	kW, rateclass peak	$11.39	$5,918	$7,795
SUBTOTAL						$31,003	$40,840

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2016

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 85 General Service (1,001-4,000 kW)							
CUSTOMER	Meters						
		Secondary Meters	79	Customers	$186.22	$15	$19
		Primary Meters	80	Customers	$1,794.23	$144	$189
	Service Design & Transformer						
		Secondary Customers	79	Customers	$4,112.80	$325	$428
		Primary Customers	80	Customers	$864.59	$69	$91
FACILITIES	Feeder Backbone		210,952	kW, rateclass peak	$21.35	$4,504	$5,933
	Feeder Local Facilities		277,074	Design Demand	$4.89	$1,355	$1,785
DEMAND	Subtransmission		214,011	kW, rateclass peak	$12.38	$2,649	$3,490
	Substation		210,952	kW, rateclass peak	$11.39	$2,403	$3,165
SUBTOTAL						$11,463	$15,100
Schedule 89 General Service (4,000 plus kW)							
CUSTOMER	Meters						
		Secondary Meters	1	Customers	$195.47	$0	$0
		Primary Meters	27	Customers	$1,785.30	$48	$63
		Substation Meters	8	Customers	$17,752.55	$142	$187
	Service Design & Transformer						
		Secondary Customers	1	Customers	$13,785.61	$14	$18
		Primary Customers	27	Customers	$2,566.49	$69	$91
FACILITIES	Feeder Backbone						
		Secondary Customers	1	Customers	$85,119.00	$85	$112
		Primary Customers	27	Customers	$85,119.00	$2,298	$3,027
		Subtransmission 115 kV Feeder	8	Customers	$86,451.00	$692	$911
DEMAND	Subtransmission		260,625	kW, rateclass peak	$12.38	$3,227	$4,250
	Substation (Sec. & Prim. Only)		201,536	kW, rateclass peak	$11.39	$2,295	$3,024
SUBTOTAL						$8,870	$11,685
Schedule 90 Primary Voltage Service							
CUSTOMER	Meters						
		Primary Meters	4	Customers	$1,773.01	$7	$9
	Service Design & Transformer						
		Primary Customers	4	Customers	$2,566.49	$10	$14
FACILITIES	Feeder Backbone						
		Primary Customers	4	Customers	$269,070.00	$1,076	$1,418
DEMAND	Subtransmission		208,777	kW, rateclass peak	$12.38	$2,585	$3,405
	Substation (Sec. & Prim. Only)		205,793	kW, rateclass peak	$11.39	$2,344	$3,088
SUBTOTAL						$6,022	$7,933
Schedules 91 & 95 Streetlighting & Highway Lighting							
CUSTOMER	Customer Service		155,359	Lights	$3.88	$604	$795
	Service Design & Transformer		155,359	Lights	$3.28	$510	$671
FACILITIES	Feeder Backbone		19,006	kW, rateclass peak	$24.76	$471	$620
	Feeder Local Facilities		19,006	Design Demand	$16.86	$320	$422
DEMAND	Subtransmission		19,281	kW, rateclass peak	$12.38	$239	$314
	Substation		19,006	kW, rateclass peak	$11.39	$216	$285
FIXED	Luminaires & Poles						**$5,592**
SUBTOTAL						$2,359	$8,700

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2016

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 92 Traffic Signals						
CUSTOMER	Service Design & Transformer	1,721	Intersections	$8.06	$14	$18
FACILITIES	Feeder Backbone	381	kW, rateclass peak	$24.76	$9	$12
	Feeder Local Facilities	381	Design Demand	$9.16	$3	$5
DEMAND	Subtransmission	387	kW, rateclass peak	$12.38	$5	$6
	Substation	381	kW, rateclass peak	$11.39	$4	$6
SUBTOTAL					$36	$47
Summary						
CUSTOMER	Meters	856,573	Customers		$21,249	$27,990
	Service Design & Transformer		Customers		$83,274	$109,693
	Customer Service	175,876	Lights		$683	$900
FACILITIES	Feeder Backbone	3,721,111	kW, rateclass peak		$95,797	$126,189
	Feeder Local Facilities	5,673,311	Design Demand		$76,817	$101,188
DEMAND	Subtransmission	4,244,471	kW, rateclass peak		$52,547	$69,217
	Substation	4,128,440	kW rateclass peak		$47,023	$61,941
FIXED	Luminaires & Poles					$7,298
TOTALS					$377,389	$504,416
					TARGET	$504,416
				EQUAL PERCENT		131.7%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2016

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	748,270	$0.43	$322	$5,675
Three Phase	143	$0.43	$0	$1
Schedule 15				
Residential	882	$0.00	$0	$0
Commercial	1,372	$0.00	$0	$0
Schedule 32				
Single Phase	54,838	$0.94	$52	$909
Three Phase	35,546	$0.94	$33	$589
Schedule 38				
Single Phase	66	$12.91	$1	$15
Three Phase	482	$12.91	$6	$110
Schedule 47				
Single Phase	231	$0.78	$0	$3
Three Phase	2,921	$0.78	$2	$40
Schedule 49				
Single Phase	3	$1.30	$0	$0
Three Phase	1,346	$1.30	$2	$31
Schedule 83				
Single Phase	645	$4.81	$3	$55
Three Phase	10,384	$4.81	$50	$881
Schedule 85				
Secondary	1,343	$13.62	$18	$323
Primary	156	$13.62	$2	$37
Schedule 85 1-4 MW				
Secondary	79	$13.62	$1	$19
Primary	80	$13.62	$1	$19
Schedule 89 GT 4 MW				
Secondary	1	$0.40	$0	$0
Primary	27	$0.40	$0	$0
Subtransmission	8	$0.40	$0	$0
Schedule 90-P	4	$0.29	$0	$0
Schedules 91/95	205	$0.00	$0	$0
Schedule 92	17	$0.00	$0	$0
TOTAL	859,049		$494	$8,708
			TARGET	$8,708
		EQUAL PERCENT		1764%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2016

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	748,270	$48.85	$36,553	$53,490
Three Phase	143	$48.85	$7	$10
Schedule 15				
Residential	882	$50.05	$44	$65
Commercial	1,372	$37.52	$51	$75
Schedule 32				
Single Phase	54,838	$40.66	$2,230	$3,263
Three Phase	35,546	$40.66	$1,445	$2,115
Schedule 38				
Single Phase	66	$121.80	$8	$12
Three Phase	482	$121.80	$59	$86
Schedule 47				
Single Phase	231	$48.36	$11	$16
Three Phase	2,921	$48.36	$141	$207
Schedule 49				
Single Phase	3	$48.64	$0	$0
Three Phase	1,346	$48.64	$65	$96
Schedule 83				
Single Phase	645	$63.81	$41	$60
Three Phase	10,384	$63.81	$663	$970
Schedule 85				
Secondary	1,343	$144.06	$193	$283
Primary	156	$144.06	$22	$33
Schedule 85 1-4 MW				
Secondary	79	$144.06	$11	$17
Primary	80	$144.06	$12	$17
Schedule 89 GT 4 MW				
Secondary	1	$125.35	$0	$0
Primary	27	$125.35	$3	$5
Subtransmission	8	$125.35	$1	$1
Schedule 90-P	4	$22.76	$0	$0
Schedules 91/95	205	$813.18	$167	$244
Schedule 92	17	$764.67	$13	$19
TOTAL	859,049		$41,742	$61,084
			TARGET	$61,084
		EQUAL PERCENT		146%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2016

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	748,270	$19.60	$14,666	$37,455
Three Phase	143	$19.60	$3	$7
Schedule 15				
Residential	882	$18.19	$16	$41
Commercial	1,372	$16.93	$23	$59
Schedule 32				
Single Phase	54,838	$28.86	$1,583	$4,042
Three Phase	35,546	$28.86	$1,026	$2,620
Schedule 38				
Single Phase	66	$186.66	$12	$31
Three Phase	482	$186.66	$90	$230
Schedule 47				
Single Phase	231	$27.49	$6	$16
Three Phase	2,921	$27.49	$80	$205
Schedule 49				
Single Phase	3	$85.74	$0	$1
Three Phase	1,346	$85.74	$115	$295
Schedule 83				
Single Phase	645	$154.95	$100	$255
Three Phase	10,384	$154.95	$1,609	$4,109
Schedule 85				
Secondary	1,343	$728.57	$978	$2,498
Primary	156	$728.57	$114	$290
Schedule 85 1-4 MW				
Secondary	79	$728.57	$58	$147
Primary	80	$728.57	$58	$149
Schedule 89 GT 4 MW				
Secondary	1	$5,272.21	$5	$13
Primary	27	$5,272.21	$142	$364
Subtransmission	8	$5,272.21	$42	$108
Schedule 90-P	4	$17,960.45	$72	$183
Schedule 91/95	205	$132.80	$27	$70
Schedule 92	17	$65.07	$1	$3
TOTAL	859,049		$20,828	$53,192
			TARGET	$53,192
		EQUAL PERCENT		255%

PORTLAND GENERAL ELECTRIC
Allocation of Carty Revenue Requirements

Schedule	Cycle MWh	Generation Revenues	Carty Allocation	Carty Price	Cycle Revenues
Schedule 7	7,620,805	$507,223,878	$38,069,230	5.00	$38,104,027
Schedule 15	16,308	$875,087	$65,679	4.03	$65,721
Schedule 32	1,599,950	$99,676,905	$7,481,160	4.68	$7,487,767
Schedule 38	39,036	$2,627,411	$197,198	5.05	$197,131
Schedule 47	20,845	$1,298,635	$97,468	4.68	$97,554
Schedule 49	62,677	$4,218,822	$316,640	5.05	$316,521
Schedule 83	2,795,179	$170,662,566	$12,808,925	4.58	$12,801,922
Schedule 85S	2,464,564	$147,421,181	$11,064,563	4.49	$11,065,894
Schedule 85P	713,162	$41,574,566	$3,120,341	4.38	$3,123,649
Schedule 89S	0	$0	$0	4.35	$0
Schedule 89P	851,370	$48,420,297	$3,634,142	4.27	$3,635,348
Schedule 89T	83,072	$4,723,942	$354,551	4.27	$354,718
Schedule 90P	1,498,007	$80,759,055	$6,061,298	4.05	$6,066,930
Schedule 91/95	74,544	$4,000,053	$300,220	4.03	$300,414
Schedule 92	3,243	$177,840	$13,348	4.12	$13,361
Totals	17,842,764	$1,113,660,238	$83,584,763		$83,630,957
Calendar Revenue Requirement			$83,583,000		
Add: Employee Discount			$40,513		
Revenue Requirement			$83,623,513		
Adjusted for Cycle			$83,584,763		

PORTLAND GENERAL ELECTRIC

PROPOSED
Summary of Area and Streetlighting Revenue

Schedule 15 - Area Lighting	
Fixtures & Maintenance	$1,152,197
Poles	$554,241
Energy (volumetric c/kWh rate)	$1,750,809
Total	**$3,457,248**

Schedule 91/95 - Street and Highway Lighting	
Fixtures & Maintenance (Options A&B)	$3,079,646
Poles (Options A&B)	$2,512,207
Energy (volumetric c/kWh rate)	$8,003,726
Total	**$13,595,579**

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum CODE	Light Description	Type	Watts	Monthly kWh	Category	Tariff Rates A	Tariff Rates B	Monthly Energy	DAX Sch 91 & 95 A & B RATES A	DAX B	DAX C	DAX TOTAL	Proposed Sch 91 & 95 A & B Counts A	Counts B	Counts C	Counts TOTAL	Annual MWh	Annual Fixed Revenue A	Annual Fixed Revenue B	Annual Energy
79	Cobrahead - PD	HPS	70-watt	30	Standard	$0.00	$1.33	$3.22	$0.00	$2.86	$1.53		-	-	1	1	30	$0	$0	$39
84	Cobrahead - PD	HPS	100-watt	43	Standard	$0.00	$1.32	$4.62	$0.00	$3.52	$2.20		1	5,677	127	5,805	43	$0	$89,924	$321,829
85	Cobrahead - PD	HPS	150-watt	62	Standard	$0.00	$1.33	$6.66	$0.00	$4.50	$3.17		-	415	111	526	62	$0	$6,623	$42,038
89	Cobrahead - PD	HPS	200-watt	79	Standard	$0.00	$1.37	$8.48	$0.00	$5.41	$4.04		-	1,189	150	1,339	79	$0	$19,547	$136,257
86	Cobrahead - PD	HPS	250-watt	102	Standard	$0.00	$1.35	$10.95	$0.00	$6.56	$5.21		-	606	225	831	102	$0	$9,817	$109,193
87	Cobrahead - PD	HPS	400-watt	163	Standard	$0.00	$1.39	$17.51	$0.00	$9.72	$8.33		-	1,537	446	1,983	163	$0	$25,637	$416,668
33	Cobrahead	HPS	70-watt	30	Standard	$4.70	$1.57	$3.22	$6.23	$3.10	$1.53		23	392	546	961	30	$1,297	$7,385	$37,133
34	Cobrahead	HPS	100-watt	43	Standard	$4.68	$1.55	$4.62	$6.88	$3.75	$2.20		505	8,132	535	9,172	43	$28,361	$151,255	$508,496
35	Cobrahead	HPS	150-watt	62	Standard	$4.78	$1.57	$6.66	$7.95	$4.74	$3.17		11	2,899	348	3,258	62	$631	$54,617	$260,379
39	Cobrahead	HPS	200-watt	79	Standard	$5.41	$1.62	$8.48	$9.45	$5.66	$4.04		124	3,619	691	4,434	79	$8,050	$70,353	$451,204
36	Cobrahead	HPS	250-watt	102	Standard	$5.35	$1.61	$10.95	$10.56	$6.82	$5.21		34	1,738	888	2,660	102	$2,183	$33,578	$349,524
37	Cobrahead	HPS	400-watt	163	Standard	$5.51	$1.62	$17.51	$13.84	$9.95	$8.33		746	1,217	878	2,841	163	$49,326	$23,658	$596,951
31	Flood	HPS	250-watt	102	Standard	$5.78	$1.66	$10.95	$10.99	$6.87	$5.21		134	2	1	137	102	$9,294	$40	$18,002
32	Flood	HPS	400-watt	163	Standard	$5.78	$1.66	$17.51	$14.11	$9.99	$8.33		305	37	10	352	163	$21,155	$737	$73,962
40	Post-Top	HPS	100-watt	43	Standard	$5.10	$1.61	$4.62	$7.30	$3.81	$2.20		4,711	4,089	878	9,678	43	$288,313	$78,999	$536,548
76	Shoebox	HPS	70-watt	30	Standard	$6.14	$1.76	$3.22	$7.67	$3.29	$1.53		2	81	5	88	30	$147	$1,711	$3,400
77	Shoebox	HPS	100-watt	43	Standard	$5.84	$1.71	$4.62	$8.04	$3.91	$2.20		24	4,898	2,403	7,325	43	$1,682	$100,507	$406,098
78	Shoebox	HPS	150-watt	62	Standard	$6.04	$1.74	$6.66	$9.21	$4.91	$3.17		2	445	132	579	62	$145	$9,292	$46,274
81	Special Acorn	HPS	100-watt	43	Custom	$8.61	$2.05	$4.62	$10.81	$4.25	$2.20		726	3,633	733	5,092	43	$75,010	$89,372	$282,300
82	Victorian	HPS	150-watt	62	Custom	$8.65	$2.06	$6.66	$11.82	$5.23	$3.17		76	1,324	256	1,656	62	$7,889	$32,729	$132,348
49	Victorian	HPS	200-watt	79	Custom	$9.41	$2.17	$8.48	$13.45	$6.21	$4.04		3	197	-	200	79	$339	$5,130	$20,352
83	Victorian	HPS	250-watt	102	Custom	$9.41	$2.17	$10.95	$14.62	$7.38	$5.21		77	1,008	87	1,172	102	$8,695	$26,248	$154,001
64	Capitol Acorn	HPS	100-watt	43	Custom	$11.92	$2.49	$4.62	$14.12	$4.69	$2.20		4	64	-	68	43	$572	$1,912	$3,770
67	Capitol Acorn	HPS	150-watt	62	Custom	$11.22	$2.41	$6.66	$14.39	$5.58	$3.17		-	309	-	309	62	$0	$8,936	$24,695
65	Capitol Acorn	HPS	200-watt	79	Custom	$12.75	$2.62	$8.48	$16.79	$6.66	$4.04		1	51	-	52	79	$153	$1,603	$5,292
66	Capitol Acorn	HPS	250-watt	102	Custom	$11.22	$2.41	$10.95	$16.43	$7.62	$5.21		-	-	-	0	102	$0	$0	$0
12	Acorn - Indep.	HPS	100-watt	43	Custom	$9.42	$2.14	$4.62	$11.62	$4.34	$2.20		36	7	22	65	43	$4,069	$180	$3,604
13	Acorn - Indep.	HPS	150-watt	62	Custom	$8.42	$2.01	$6.66	$11.59	$5.18	$3.17		-	6	6	12	62	$0	$145	$959
98	Techtra	HPS	100-watt	43	Custom	$18.17	$3.32	$4.62	$20.37	$5.52	$2.20		508	38	4	550	43	$110,764	$1,514	$30,492
99	Techtra	HPS	150-watt	62	Custom	$17.56	$3.24	$6.66	$20.73	$6.41	$3.17		12	138	-	150	62	$2,529	$5,365	$11,988
88	Techtra	HPS	250-watt	102	Custom	$17.49	$3.24	$10.95	$22.70	$8.45	$5.21		-	58	142	200	102	$0	$2,255	$26,280
90	Westbrooke Acorn	HPS	70-watt	30	Custom	$11.45	$2.43	$3.22	$12.98	$3.96	$1.53		1	25	-	26	30	$137	$729	$1,005
91	Westbrooke Acorn	HPS	100-watt	43	Custom	$10.87	$2.34	$4.62	$13.07	$4.54	$2.20		31	145	-	176	43	$4,044	$4,072	$9,757
92	Westbrooke Acorn	HPS	150-watt	62	Custom	$10.88	$2.35	$6.66	$14.05	$5.52	$3.17		-	61	-	61	62	$0	$1,720	$4,875
93	Westbrooke Acorn	HPS	200-watt	79	Custom	$11.07	$2.38	$8.48	$15.11	$6.42	$4.04		-	5	-	5	79	$0	$143	$509
94	Westbrooke Acorn	HPS	250-watt	102	Custom	$11.26	$2.41	$10.95	$16.47	$7.62	$5.21		73	35	-	108	102	$9,864	$1,012	$14,191
62	Cobrahead	MH	150-watt	60	Custom	$5.28	$1.87	$6.44	$8.35	$4.94	$3.07		-	-	-	0	60	$0	$0	$0
61	Flood	MH	350-watt	139	Custom	$6.03	$1.94	$14.93	$13.13	$9.04	$7.10		-	-	-	0	139	$0	$0	$0
47	Flood	HPS	750-watt	285	Custom	$9.14	$2.88	$30.61	$23.70	$17.44	$14.56		54	-	-	54	285	$5,923	$0	$19,835
9	Mongoose	HPS	150-watt	62	Custom	$8.98	$2.10	$6.66	$12.15	$5.27	$3.17		-	27	-	27	62	$0	$680	$2,158
10	Mongoose	HPS	250-watt	102	Custom	$8.38	$2.01	$10.95	$13.59	$7.22	$5.21		-	8	-	8	102	$0	$193	$1,051
18	Ornamental Acorn Twin / Opt C	QL	85-watt	64	Custom	$0.00	$0.00	$6.87	$0.00	$0.00	$3.27		-	-	672	672	64	$0	$0	$55,400
20	Ornamental Acorn / Opt C	QL	55-watt	21	Custom	$0.00	$0.00	$2.26	$0.00	$0.00	$1.07		-	-	5	5	21	$0	$0	$136
26	Ornamental Acorn Twin / Opt C	QL	55-watt	42	Custom	$0.00	$0.00	$4.51	$0.00	$0.00	$2.15		-	-	10	10	42	$0	$0	$541
44	Composite Twin / Opt C	Comp	140-watt	54	Custom	$0.00	$0.00	$5.80	$0.00	$0.00	$2.76		-	-	38	38	54	$0	$0	$2,645
45	Composite Twin / Opt C	Comp	175-watt	66	Custom	$0.00	$0.00	$7.09	$0.00	$0.00	$3.37		-	-	99	99	66	$0	$0	$8,423
19	Cobrahead - (C) Only	MV	100-watt	39	Obsolete	$0.00	$0.00	$4.19	$0.00	$0.00	$1.99		-	-	2	2	39	$0	$0	$101
21	Cobrahead	MV	175-watt	66	Obsolete	$4.64	$1.51	$7.09	$8.01	$4.88	$3.37		92	802	87	981	66	$5,123	$14,532	$83,463
22	Cobrahead	MV	250-watt	94	Obsolete	$0.00	$0.00	$10.10	$0.00	$0.00	$4.80		-	-	23	23	94	$0	$0	$2,788
23	Cobrahead	MV	400-watt	147	Obsolete	$5.43	$1.64	$15.79	$12.94	$9.15	$7.51		37	42	75	154	147	$2,411	$827	$29,180
24	Cobrahead	MV	1,000-watt	374	Obsolete	$5.83	$1.94	$40.17	$24.94	$21.05	$19.11		8	3	1	12	374	$560	$70	$5,784
50	Special Box - Space-Glo	HPS	70-watt	30	Obsolete	$5.78	$1.65	$3.22	$7.31	$3.18	$1.53		21	-	-	21	30	$1,457	$0	$811
46	Special Box - Space-Glo	MV	175-watt	66	Obsolete	$5.74	$1.61	$7.09	$9.11	$4.98	$3.37		17	136	23	176	66	$1,171	$2,628	$14,974
51	Box - Gardco Hub / Opt C	HPS	Twin 70-watt	60	Obsolete	$0.00	$0.00	$6.44	$0.00	$0.00	$3.07		-	-	123	123	60	$0	$0	$9,505
52	Box - Gardco Hub / Opt C	HPS	70-watt	30	Obsolete	$0.00	$0.00	$3.22	$0.00	$0.00	$1.53		-	-	199	199	30	$0	$0	$7,689
53	Box - Gardco Hub	HPS	100-watt	43	Obsolete	$0.00	$1.99	$4.62	$0.00	$4.19	$2.20		-	10	4	14	43	$0	$239	$776
54	Box - Gardco Hub	HPS	150-watt	62	Obsolete	$0.00	$2.01	$6.66	$0.00	$5.18	$3.17		-	61	54	115	62	$0	$1,471	$9,191
55	Box - Gardco Hub / Opt C	HPS	250-watt	102	Obsolete	$0.00	$0.00	$10.95	$0.00	$0.00	$5.21		-	-	236	236	102	$0	$0	$31,010
56	Box - Gardco Hub / Opt C	HPS	400-watt	163	Obsolete	$0.00	$0.00	$17.51	$0.00	$0.00	$8.33		-	-	110	110	163	$0	$0	$23,113
58	Box - Gardco Hub	MH	250-watt	99	Obsolete	$0.00	$1.26	$10.63	$0.00	$6.32	$5.06		-	7	8	15	99	$0	$106	$1,913
59	Box - Gardco Hub	MH	400-watt	156	Obsolete	$0.00	$1.26	$16.75	$0.00	$9.23	$7.97		-	27	-	27	156	$0	$408	$5,427
48	Cobrahead	MH	175-watt	71	Obsolete	$5.32	$1.72	$7.63	$8.95	$5.35	$3.63		-	3	57	60	71	$0	$62	$5,494
60	Flood	MH	400-watt	156	Obsolete	$5.96	$1.88	$16.75	$13.93	$9.85	$7.97		21	1	12	34	156	$1,502	$23	$6,834
69	Cobrahead DW 70/100	HPS	100-watt	43	Obsolete	$0.00	$1.57	$4.62	$0.00	$3.77	$2.20		-	88	-	88	43	$0	$1,658	$4,879
70	Cobrahead DW 100/150	HPS	100-watt	43	Obsolete	$0.00	$1.57	$4.62	$0.00	$3.77	$2.20		-	381	-	381	43	$0	$7,178	$21,123
71	Cobrahead DW 100/150	HPS	150-watt	62	Obsolete	$0.00	$1.59	$6.66	$0.00	$4.76	$3.17		-	299	5	304	62	$0	$5,705	$24,296
2	Victorian	QL	85-watt	32	Obsolete	$0.00	$0.73	$3.44	$0.00	$2.36	$1.63		-	-	487	487	32	$0	$0	$20,103
1	Victorian	QL	165-watt	60	Obsolete	$0.00	$0.88	$6.44	$0.00	$3.95	$3.07		-	-	376	376	60	$0	$0	$29,057
3	Techtra	QL	165-watt	60	Obsolete	$18.94	$1.16	$6.44	$22.01	$4.23	$3.07		4	156	-	160	60	$909	$2,172	$12,365
95	KIM SBC Shoebox	HPS	150-watt	62	Obsolete	$0.00	$2.53	$6.66	$0.00	$5.70	$3.17		-	34	66	100	62	$0	$1,032	$7,992
96	KIM Archetype	HPS	250-watt	102	Obsolete	$0.00	$2.58	$10.95	$0.00	$7.79	$5.21		-	65	23	88	102	$0	$2,012	$11,563
97	KIM Archetype	HPS	400-watt	163	Obsolete	$0.00	$2.24	$17.51	$0.00	$10.57	$8.33		-	17	28	45	163	$0	$457	$9,455
80	Acorn Type	HPS	70-watt	30	Obsolete	$8.63	$2.07	$3.22	$10.16	$3.60	$1.53		22	7	-	29	30	$2,278	$174	$1,121
73	GardCo Bronze - (C) Only	HPS	70-watt	30	Obsolete	$0.00	$0.00	$3.22	$0.00	$0.00	$1.53		-	-	27	27	30	$0	$0	$1,043
72	GardCo Bronze - (C) Only	MV	175-watt	66	Obsolete	$0.00	$0.00	$7.09	$0.00	$0.00	$3.37		-	-	113	113	66	$0	$0	$9,614
74	Acrylic Sphere - (C) Only	MV	400-watt	147	Obsolete	$0.00	$0.00	$15.79	$0.00	$0.00	$7.51		-	-	-	0	147	$0	$0	$0
25	Post-Top - Black	HPS	70-watt	30	Obsolete	$5.03	$1.54	$3.22	$6.56	$3.07	$1.53		1,497	1,193	21	2,711	30	$90,359	$22,047	$104,753

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum CODE	Light Description	Type	Watts	Monthly kWh	Category	Tariff Rates A	Tariff Rates B	Monthly Energy	DAX Sch 91 & 95 A & B RATES A	DAX B	DAX C	DAX TOTAL	Proposed Sch 91 & 95 A & B Counts A	Counts B	Counts C	Counts TOTAL	Annual MWh	Annual Fixed Revenue A	Annual Fixed Revenue B	Annual Energy
43	Rect.Type - (C) Only	HPS	200-watt	79	Obsolete	$0.00	$0.00	$8.48	$0.00	$0.00	$4.04		-	-	166	166	79	$0	$0	$16,892
5	Incand. - (C) Only	IND	92-watt	31	Obsolete	$0.00	$0.00	$3.33	$0.00	$0.00	$1.58		-	-	25	25	31	$0	$0	$999
6	Incand. - (C) Only	IND	182-watt	62	Obsolete	$0.00	$0.00	$6.66	$0.00	$0.00	$3.17		-	-	4	4	62	$0	$0	$320
29	Town and Country Post-Top	MV	175-watt	66	Obsolete	$5.04	$1.55	$7.09	$8.41	$4.92	$3.37		82	1,083	7	1,172	66	$4,959	$20,144	$99,714
27	Flood	HPS	70-watt	30	Obsolete	$4.58	$1.45	$3.22	$6.11	$2.98	$1.53		1	-	-	1	30	$55	$0	$39
30	Flood	HPS	100-watt	43	Obsolete	$4.54	$1.56	$4.62	$6.74	$3.76	$2.20		47	6	1	54	43	$2,561	$112	$2,994
38	Flood	HPS	200-watt	79	Obsolete	$5.82	$1.70	$8.48	$9.86	$5.74	$4.04		179	39	3	221	79	$12,501	$796	$22,489
41	Cobrahead - PD	HPS	310-watt	124	Obsolete	$5.75	$2.01	$13.32	$12.09	$8.35	$6.34		5	15	-	20	124	$345	$362	$3,197
14	Ornamental - (C) Only	HPS	100-watt	43	Obsolete	$0.00	$0.00	$4.62	$0.00	$0.00	$2.20		-	-	1,765	1,765	43	$0	$0	$97,852
15	Twin Ornamental -(C) Only	HPS	Twin 100-watt	86	Obsolete	$0.00	$0.00	$9.24	$0.00	$0.00	$4.39		-	-	2,193	2,193	86	$0	$0	$243,160
7	Flourescent - (C) Only	FLR	28-watt	12	Obsolete	$0.00	$0.00	$1.29	$0.00	$0.00	$0.61		-	-	13	13	12	$0	$0	$201
100	Cobrahead	LED	37-watt	13	Standard	$2.95	*	$1.40	$3.61	*	*		1,719	-	-	1,719	13	$60,853	*	$28,879
101	Cobrahead	LED	50-watt	17	Standard	$2.95	*	$1.83	$3.82	*	*		25,377	-	-	25,377	17	$898,346	*	$557,279
102	Cobrahead	LED	52-watt	18	Standard	$3.28	*	$1.93	$4.20	*	*		1,970	-	-	1,970	18	$77,539	*	$45,625
103	Cobrahead	LED	67-watt	23	Standard	$3.66	*	$2.47	$4.84	*	*		5,471	-	-	5,471	23	$240,286	*	$162,160
104	Cobrahead	LED	106-watt	36	Standard	$4.36	*	$3.87	$6.20	*	*		1,606	-	-	1,606	36	$84,026	*	$74,583
110	Acorn	LED	60-Watt	21	Custom	$11.43	*	$2.26	$12.50	*	*		-	-	-	0	21	$0	*	$0
111	Acorn	LED	70-Watt	24	Custom	$13.24	*	$2.58	$14.47	*	*		-	-	-	0	24	$0	*	$0
112	Westbrooke (non-fluted)	LED	53-Watt	18	Custom	$15.65	*	$1.93	$16.57	*	*		-	-	-	0	18	$0	*	$0
113	Westbrooke (non-fluted)	LED	69-Watt	24	Custom	$15.06	*	$2.58	$16.29	*	*		-	-	-	0	24	$0	*	$0
114	Westbrooke (non-fluted)	LED	85-Watt	29	Custom	$15.27	*	$3.11	$16.75	*	*		-	-	-	0	29	$0	*	$0
115	Westbrooke (non-fluted)	LED	136-Watt	46	Custom	$18.34	*	$4.94	$20.69	*	*		-	-	-	0	46	$0	*	$0
116	Westbrooke (non-fluted)	LED	206-Watt	70	Custom	$18.27	*	$7.52	$21.85	*	*		-	-	-	0	70	$0	*	$0
117	Westbrooke (fluted)	LED	53-Watt	18	Custom	$17.79	*	$1.93	$18.71	*	*		-	-	-	0	18	$0	*	$0
118	Westbrooke (fluted)	LED	69-Watt	24	Custom	$17.79	*	$2.58	$19.02	*	*		-	-	-	0	24	$0	*	$0
119	Westbrooke (fluted)	LED	85-Watt	29	Custom	$16.73	*	$3.11	$18.21	*	*		-	-	-	0	29	$0	*	$0
120	Westbrooke (fluted)	LED	136-Watt	46	Custom	$19.43	*	$4.94	$21.78	*	*		-	-	-	0	46	$0	*	$0
121	Westbrooke (fluted)	LED	206-Watt	70	Custom	$19.43	*	$7.52	$23.01	*	*		-	-	-	0	70	$0	*	$0
148	20 - 25	LED		8		*	*	$0.86	*	*	$0.41		-	-	-	0	8	*	*	$0
149	>25 - 30	LED		9		*	*	$0.97	*	*	$0.46		-	-	4,485	4,485	9	*	*	$52,205
150	>30 - 35	LED		11		*	*	$1.18	*	*	$0.56		-	-	-	0	11	*	*	$0
151	>35 - 40	LED		13		*	*	$1.40	*	*	$0.66		-	-	510	510	13	*	*	$8,568
152	>40 - 45	LED		15		*	*	$1.61	*	*	$0.77		-	-	2,297	2,297	15	*	*	$44,378
153	>45 - 50	LED		16		*	*	$1.72	*	*	$0.82		-	-	21,621	21,621	16	*	*	$446,257
154	>50 - 55	LED		18		*	*	$1.93	*	*	$0.92		-	-	5,928	5,928	18	*	*	$137,292
155	>55 - 60	LED		20		*	*	$2.15	*	*	$1.02		-	-	8	8	20	*	*	$206
156	>60 - 65	LED		21		*	*	$2.26	*	*	$1.07		-	-	132	132	21	*	*	$3,580
157	>65 - 70	LED		23		*	*	$2.47	*	*	$1.18		-	-	4,705	4,705	23	*	*	$139,456
158	>70 - 75	LED		25		*	*	$2.69	*	*	$1.28		-	-	24	24	25	*	*	$775
159	>75 - 80	LED		26		*	*	$2.79	*	*	$1.33		-	-	11	11	26	*	*	$368
160	>80 - 85	LED		28		*	*	$3.01	*	*	$1.43		-	-	-	0	28	*	*	$0
161	>85 - 90	LED		30		*	*	$3.22	*	*	$1.53		-	-	337	337	30	*	*	$13,022
162	>90 - 95	LED		32		*	*	$3.44	*	*	$1.63		-	-	-	0	32	*	*	$0
163	>95 - 100	LED		33		*	*	$3.54	*	*	$1.69		-	-	2	2	33	*	*	$85
164	>100 - 110	LED		36		*	*	$3.87	*	*	$1.84		-	-	3,169	3,169	36	*	*	$147,168
165	>110 - 120	LED		39		*	*	$4.19	*	*	$1.99		-	-	-	0	39	*	*	$0
166	>120 - 130	LED		43		*	*	$4.62	*	*	$2.20		-	-	-	0	43	*	*	$0
167	>130 - 140	LED		46		*	*	$4.94	*	*	$2.35		-	-	143	143	46	*	*	$8,477
168	>140 - 150	LED		50		*	*	$5.37	*	*	$2.55		-	-	-	0	50	*	*	$0
169	>150 - 160	LED		53		*	*	$5.69	*	*	$2.71		-	-	-	0	53	*	*	$0
170	>160 - 170	LED		56		*	*	$6.01	*	*	$2.86		-	-	25	25	56	*	*	$1,803
171	>170 - 180	LED		60		*	*	$6.44	*	*	$3.07		-	-	2	2	60	*	*	$155
172	>180 - 190	LED		63		*	*	$6.77	*	*	$3.22		-	-	71	71	63	*	*	$5,768
173	>190 - 200	LED		67		*	*	$7.20	*	*	$3.42		-	-	13	13	67	*	*	$1,123
174	>200 - 210	LED		70		*	*	$7.52	*	*	$3.58		-	-	11	11	70	*	*	$993
175	>210 - 220	LED		73		*	*	$7.84	*	*	$3.73		-	-	-	0	73	*	*	$0
176	>220 - 230	LED		77		*	*	$8.27	*	*	$3.93		-	-	60	60	77	*	*	$5,954
177	>230 - 240	LED		80		*	*	$8.59	*	*	$4.09		-	-	-	0	80	*	*	$0
178	>240 - 250	LED		84		*	*	$9.02	*	*	$4.29		-	-	-	0	84	*	*	$0
179	>250 - 260	LED		87		*	*	$9.34	*	*	$4.44		-	-	-	0	87	*	*	$0
180	>260 - 270	LED		91		*	*	$9.77	*	*	$4.65		-	-	17	17	91	*	*	$1,993
181	>270 - 280	LED		94		*	*	$10.10	*	*	$4.80		-	-	14	14	94	*	*	$1,697
182	>280 - 290	LED		97		*	*	$10.42	*	*	$4.96		-	-	-	0	97	*	*	$0
183	>290 - 300	LED		101		*	*	$10.85	*	*	$5.16		-	-	-	0	101	*	*	$0
								Totals					46,400	48,587	60,371	155,358	9,060	$2,127,812	$951,834	$8,003,726

Notes:
1. Obsolete fixtures are not available to new service
2. Option C are customer owned and maintained and only pay the respective energy charge

PORTLAND GENERAL ELECTRIC

Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
57	Black	Fiberglass	20	A	$4.91	4,153	$244,695
59	Bronze	Fiberglass	30	A	$7.74	2,520	$234,058
61	Gray	Fiberglass	30	A	$8.35	4,495	$450,399
1	Standard	Wood	30 to 35	A	$5.59	1,405	$94,247
3	Standard	Wood	40 to 55	A	$7.31	159	$13,947
58	Black	Fiberglass	20	B	$0.15	5,242	$9,436
60	Bronze	Fiberglass	30	B	$0.23	6,175	$17,043
62	Gray	Fiberglass	30	B	$0.25	9,451	$28,353
46	Standard	Wood	30 to 35	B	$0.17	323	$659
47	Standard	Wood	40 to 55	B	$0.22	136	$359
31	Regular	Aluminum	16	A	$6.67	569	$45,543
32	Regular	Aluminum	25	A	$11.07	4,400	$584,496
33	Regular	Aluminum	30	A	$11.96	231	$33,153
28	Regular	Aluminum	35	A	$14.30	80	$13,728
18	Davit	Aluminum	25	A	$11.05	63	$8,354
6	Davit	Aluminum	30	A	$10.99	430	$56,708
29	Davit	Aluminum	35	A	$12.02	639	$92,169
70	Davit with 8-foot Arm	Aluminum	40	A	$16.30	39	$7,628
27	Double Davit	Aluminum	30	A	$16.22	23	$4,477
65	Fluted Victorian Ornamental	Aluminum	14	A	$9.76	54	$6,324
69	Non-fluted Techtra Ornamental	Aluminum	18	A	$19.21	525	$121,023
66	Fluted Ornamental	Aluminum	16	A	$9.98	108	$12,934
77	HADCO Non-fluted Ornamental	Aluminum	16	A	$20.41	1	$245
79	Fluted Westbrooke	Aluminum	18	A	$19.26	0	$0
81	Non-fluted Westbrooke	Aluminum	18	A	$20.41	97	$23,757
43	Painted Ornamental - Portland Rd.	Aluminum	35	A	$32.80	0	$0
85	Decorative Ameron	Concrete	20	A	$19.16	0	$0
4	Ameron Post Top	Concrete	25	A	$19.16	0	$0
63	Fluted Ornamental -Black	Fiberglass	14	A	$11.81	639	$90,559
83	Smooth	Fiberglass	18	A	$4.90	2	$118
67	Regular - Color may vary	Fiberglass	22	A	$4.38	19	$999
68	Regular - Color may vary	Fiberglass	35	A	$7.19	287	$24,762
16	Anchor Base -Gray	Fiberglass	35	A	$13.11	43	$6,765
35	Direct Bury with Shroud	Fiberglass	18	A	$7.92	5	$475
34	Regular	Aluminum	16	B	$0.20	83	$199
8	Regular	Aluminum	25	B	$0.33	1,075	$4,257
48	Regular	Aluminum	30	B	$0.36	693	$2,994
54	Regular	Aluminum	35	B	$0.43	500	$2,580
13	Davit	Aluminum	25	B	$0.33	154	$610
12	Davit	Aluminum	30	B	$0.33	1,346	$5,330
53	Davit	Aluminum	35	B	$0.36	1,548	$6,687
76	Davit with 8-foot Arm	Aluminum	40	B	$0.49	170	$1,000
14	Double Davit	Aluminum	30	B	$0.48	47	$271
71	Fluted Victorian Ornamental	Aluminum	14	B	$0.29	1,194	$4,155
75	Non-fluted Techtra Ornamental	Aluminum	18	B	$0.57	402	$2,750
72	Fluted Ornamental	Aluminum	16	B	$0.30	1,650	$5,940

PORTLAND GENERAL ELECTRIC

Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
78	HADCO Non-fluted Ornamental	Aluminum	16	B	$0.61	9	$66
80	Fluted Westbrooke	Aluminum	18	B	$0.57	137	$937
82	Non-fluted Westbrooke	Aluminum	18	B	$0.61	131	$959
44	Painted Ornamental - Portland Rd.	Aluminum	35	B	$0.98	61	$717
86	Decorative Ameron	Concrete	20	B	$0.57	0	$0
5	Ameron Post Top	Concrete	25	B	$0.57	0	$0
64	Fluted Ornamental -Black	Fiberglass	14	B	$0.35	1,894	$7,955
84	Smooth	Fiberglass	18	B	$0.15	4	$7
73	Regular - Color may vary	Fiberglass	22	B	$0.13	507	$791
74	Regular - Color may vary	Fiberglass	35	B	$0.21	1,649	$4,155
17	Anchor Base -Gray	Fiberglass	35	B	$0.39	87	$407
36	Direct Bury with Shroud	Fiberglass	18	B	$0.24	548	$1,578
2	Post	Aluminum	30	A	$6.67	365	$29,215
30	Ornamental Post	Concrete	35 or less	A	$11.07	57	$7,572
37	Painted Regular	Steel	25	A	$11.07	294	$39,055
38	Painted Regular	Steel	30	A	$11.96	144	$20,667
39	Laminated without Mast Arm	Wood	20	A	$4.91	1,062	$62,573
24	Laminted SLO Pole	Wood	20	A	$4.91	164	$9,663
41	Curved laminated	Wood	30	A	$7.74	210	$19,505
11	Painted Underground	Wood	35	A	$5.59	474	$31,796
22	Painted SLO Pole	Wood	35	A	$5.59	50	$3,354
55	Bronze Alloy GardCo	Bronze	12	B	$0.18	22	$48
25	Ornamental Post	Concrete	35 or less	B	$0.33	192	$760
7	Painted Regular	Steel	25	B	$0.33	224	$887
49	Painted Regular	Steel	30	B	$0.36	44	$190
21	Unpainted with 6-foot Mast Arm	Steel	30	B	$0.33	50	$198
51	Unpainted with 6-foot Davit Arm	Steel	30	B	$0.33	35	$139
40	Unpainted with 8-foot Mast Arm	Steel	35	B	$0.36	78	$337
42	Unpainted with 8-foot Davit Arm	Steel	35	B	$0.36	3	$13
23	Laminated without Mast Arm	Wood	20	B	$0.15	2,004	$3,607
45	Curved laminated	Wood	30	B	$0.23	101	$279
26	Painted Underground	Wood	35	B	$0.17	290	$592
				Total Option As		23,806	$2,394,963
				Total Option Bs		38,259	$117,244
						62,065	$2,512,207

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

Code	Description	Type	Size	kWh	Monthly Tariff Price Fixed	Monthly Tariff Price Energy	Monthly Tariff Price Total	DAX Monthly Tariff Price Fixed	DAX Monthly Tariff Price Energy	DAX Monthly Tariff Price Total	Count	Annual MWh	Revenues Fixed	Revenues Energy	Revenues Total
Fixtures															
21	Cobrahead	MV	175-watt	66	$5.58	$7.09	$12.67	$5.58	$3.37	$8.95	325	257	$21,762	$27,651	$49,413
23	Cobrahead	MV	400-watt	147	$6.01	$15.79	$21.80	$6.01	$7.51	$13.52	1,701	3,001	$122,676	$322,305	$444,982
24	Cobrahead	MV	1000-watt	374	$6.41	$40.17	$46.58	$6.41	$19.11	$25.52	98	440	$7,538	$47,240	$54,778
33	Cobrahead - (non-pd)	HPS	70-watt	30	$5.65	$3.22	$8.87	$5.65	$1.53	$7.18	79	28	$5,356	$3,053	$8,409
34	Cobrahead - (non-pd)	HPS	100-watt	43	$5.62	$4.62	$10.24	$5.62	$2.20	$7.82	0	0	$0	$0	$0
35	Cobrahead - (non-pd)	HPS	150-watt	62	$5.72	$6.66	$12.38	$5.72	$3.17	$8.89	18	13	$1,236	$1,439	$2,674
39	Cobrahead - (non-pd)	HPS	200-watt	79	$5.99	$8.48	$14.47	$5.99	$4.04	$10.03	36	34	$2,588	$3,663	$6,251
36	Cobrahead - (non-pd)	HPS	250-watt	102	$5.94	$10.95	$16.89	$5.94	$5.21	$11.15	52	64	$3,707	$6,833	$10,539
41	Cobrahead - (PD)	HPS	310-watt	124	$6.34	$13.32	$19.66	$6.34	$6.34	$12.68	6	9	$456	$959	$1,416
37	Cobrahead - (non-pd)	HPS	400-watt	163	$6.09	$17.51	$23.60	$6.09	$8.33	$14.42	1,667	3,261	$121,824	$350,270	$472,094
30	Flood	HPS	100-watt	43	$5.49	$4.62	$10.11	$5.49	$2.20	$7.69	392	202	$25,825	$21,732	$47,557
38	Flood	HPS	200-watt	79	$6.40	$8.48	$14.88	$6.40	$4.04	$10.44	578	548	$44,390	$58,817	$103,208
31	Flood	HPS	250-watt	102	$6.36	$10.95	$17.31	$6.36	$5.21	$11.57	812	994	$61,972	$106,697	$168,669
32	Flood	HPS	400-watt	163	$6.36	$17.51	$23.87	$6.36	$8.33	$14.69	1,840	3,599	$140,429	$386,621	$527,050
76	Shoebox	HPS	70-watt	30	$7.08	$3.22	$10.30	$7.08	$1.53	$8.61	8	3	$680	$309	$989
77	Shoebox	HPS	100-watt	43	$6.78	$4.62	$11.40	$6.78	$2.20	$8.98	580	299	$47,189	$32,155	$79,344
78	Shoebox	HPS	150-watt	62	$6.98	$6.66	$13.64	$6.98	$3.17	$10.15	101	75	$8,460	$8,072	$16,532
81	Special Acorn	HPS	100-watt	43	$9.19	$4.62	$13.81	$9.19	$2.20	$11.39	351	181	$38,708	$19,459	$58,168
82	HADCO - Victorian	HPS	150-watt	62	$9.23	$6.66	$15.89	$9.23	$3.17	$12.40	23	17	$2,547	$1,838	$4,386
49	HADCO - Victorian	HPS	200-watt	79	$9.99	$8.48	$18.47	$9.99	$4.04	$14.03	2	2	$240	$204	$443
83	HADCO - Victorian	HPS	250-watt	102	$9.99	$10.95	$20.94	$9.99	$5.21	$15.20	0	0	$0	$0	$0
40	Early American Post-Top	HPS	100-watt	43	$6.04	$4.62	$10.66	$6.04	$2.20	$8.24	83	43	$6,016	$4,602	$10,617
62	Cobrahead	MH	150-watt	60	$6.22	$6.44	$12.66	$6.22	$3.07	$9.29	8	6	$597	$618	$1,215
48	Cobrahead	MH	175-watt	71	$6.26	$7.63	$13.89	$6.26	$3.63	$9.89	0	0	$0	$0	$0
61	Flood	MH	350-watt	139	$6.61	$14.93	$21.54	$6.61	$7.10	$13.71	157	262	$12,453	$28,128	$40,581
60	Flood	MH	400-watt	156	$6.54	$16.75	$23.29	$6.54	$7.97	$14.51	14	26	$1,099	$2,814	$3,913
47	Flood	HPS	750-watt	285	$9.73	$30.61	$40.34	$9.73	$14.56	$24.29	125	428	$14,595	$45,915	$60,510
12	HADCO Independence	HPS	100-watt	43	$10.00	$4.62	$14.62	$10.00	$2.20	$12.20	19	10	$2,280	$1,053	$3,333
13	HADCO Independence	HPS	150-watt	62	$9.00	$6.66	$15.66	$9.00	$3.17	$12.17	20	15	$2,160	$1,598	$3,758
64	HADCO Capitol Acorn	HPS	100-watt	43	$12.50	$4.62	$17.12	$12.50	$2.20	$14.70	9	5	$1,350	$499	$1,849
67	HADCO Capitol Acorn	HPS	150-watt	62	$11.80	$6.66	$18.46	$11.80	$3.17	$14.97	0	0	$0	$0	$0
65	HADCO Capitol Acorn	HPS	200-watt	79	$13.33	$8.48	$21.81	$13.33	$4.04	$17.37	0	0	$0	$0	$0
66	HADCO Capitol Acorn	HPS	250-watt	102	$11.80	$10.95	$22.75	$11.80	$5.21	$17.01	0	0	$0	$0	$0
98	HADCO Techtra	HPS	100-watt	43	$18.75	$4.62	$23.37	$18.75	$2.20	$20.95	0	0	$0	$0	$0
99	HADCO Techtra	HPS	150-watt	62	$18.14	$6.66	$24.80	$18.14	$3.17	$21.31	2	1	$435	$160	$595
88	HADCO Techtra	HPS	250-watt	102	$18.07	$10.95	$29.02	$18.07	$5.21	$23.28	0	0	$0	$0	$0
90	HADCO Westbrooke	HPS	70-watt	30	$12.03	$3.22	$15.25	$12.03	$1.53	$13.56	0	0	$0	$0	$0
91	HADCO Westbrooke	HPS	100-watt	43	$11.45	$4.62	$16.07	$11.45	$2.20	$13.65	0	0	$0	$0	$0
92	HADCO Westbrooke	HPS	150-watt	62	$11.46	$6.66	$18.12	$11.46	$3.17	$14.63	0	0	$0	$0	$0
93	HADCO Westbrooke	HPS	200-watt	79	$11.65	$8.48	$20.13	$11.65	$4.04	$15.69	0	0	$0	$0	$0
94	HADCO Westbrooke	HPS	250-watt	102	$11.84	$10.95	$22.79	$11.84	$5.21	$17.05	0	0	$0	$0	$0
96	KIM Archetype	HPS	250-watt	102	$13.20	$10.95	$24.15	$13.20	$5.21	$18.41	0	0	$0	$0	$0
97	KIM Archetype	HPS	400-watt	163	$10.69	$17.51	$28.20	$10.69	$8.33	$19.02	0	0	$0	$0	$0
9	Holophane Mongoose	HPS	150-watt	62	$9.57	$6.66	$16.23	$9.57	$3.17	$12.74	1	1	$115	$80	$195
10	Holophane Mongoose	HPS	250-watt	102	$8.96	$10.95	$19.91	$8.96	$5.21	$14.17	0	0	$0	$0	$0
100	Cobrahead	LED	37-watt	13	$3.28	$1.40	$4.68	$3.28	$0.66	$3.94	569	89	$22,396	$9,559	$31,955
101	Cobrahead	LED	50-watt	17	$3.28	$1.83	$5.11	$3.28	$0.87	$4.15	4,175	852	$164,328	$91,683	$256,011
102	Cobrahead	LED	52-watt	18	$3.62	$1.93	$5.55	$3.62	$0.92	$4.54	618	133	$26,846	$14,313	$41,159
103	Cobrahead	LED	67-watt	23	$3.85	$2.47	$6.32	$3.85	$1.18	$5.03	1,877	518	$86,717	$55,634	$142,352
104	Cobrahead	LED	106-watt	36	$4.55	$3.87	$8.42	$4.55	$1.84	$6.39	446	193	$24,352	$20,712	$45,064
110	Acorn	LED	60-Watt	21	$12.01	$2.26	$14.27	$12.01	$1.07	$13.08	8	2	$1,153	$217	$1,370
111	Acorn	LED	70-Watt	24	$13.82	$2.58	$16.40	$13.82	$1.23	$15.05	0	0	$0	$0	$0
112	Westbrooke (non-flare)	LED	53-Watt	18	$16.23	$1.93	$18.16	$16.23	$0.92	$17.15	0	0	$0	$0	$0
113	Westbrooke (non-flare)	LED	69-Watt	24	$15.64	$2.58	$18.22	$15.64	$1.23	$16.87	0	0	$0	$0	$0
114	Westbrooke (non-flare)	LED	85-Watt	29	$15.85	$3.11	$18.96	$15.85	$1.48	$17.33	0	0	$0	$0	$0
115	Westbrooke (non-flare)	LED	136-Watt	46	$18.93	$4.94	$23.87	$18.93	$2.35	$21.28	0	0	$0	$0	$0
116	Westbrooke (non-flare)	LED	206-Watt	70	$18.85	$7.52	$26.37	$18.85	$3.58	$22.43	0	0	$0	$0	$0
117	Westbrooke (flare)	LED	53-Watt	18	$18.38	$1.93	$20.31	$18.38	$0.92	$19.30	0	0	$0	$0	$0
118	Westbrooke (flare)	LED	69-Watt	24	$18.38	$2.58	$20.96	$18.38	$1.23	$19.61	0	0	$0	$0	$0
119	Westbrooke (flare)	LED	85-Watt	29	$17.31	$3.11	$20.42	$17.31	$1.48	$18.79	0	0	$0	$0	$0
120	Westbrooke (flare)	LED	136-Watt	46	$20.02	$4.94	$24.96	$20.02	$2.35	$22.37	0	0	$0	$0	$0
121	Westbrooke (flare)	LED	206-Watt	70	$20.02	$7.52	$27.54	$20.02	$3.58	$23.60	0	0	$0	$0	$0
122	CREE XSP	LED	25-Watt	9	$2.53	$0.97	$3.50	$2.53	$0.46	$2.99	388	42	$11,780	$4,516	$16,296
123	CREE XSP	LED	42-Watt	14	$2.62	$1.50	$4.12	$2.62	$0.72	$3.34	2,105	354	$66,181	$37,890	$104,071
124	CREE XSP	LED	48-Watt	16	$3.06	$1.72	$4.78	$3.06	$0.82	$3.88	370	71	$13,586	$7,637	$21,223
125	CREE XSP	LED	56-Watt	19	$3.53	$2.04	$5.57	$3.53	$0.97	$4.50	663	151	$28,085	$16,230	$44,315
126	CREE XSP	LED	91-Watt	31	$3.53	$3.33	$6.86	$3.53	$1.58	$5.11	191	71	$8,091	$7,632	$15,723
Totals											20,517	16,299	$1,152,197	$1,750,809	$2,903,007

Code	Description	Type	Size	Monthly Tariff Price Total	Count	Revenues Total
Poles						
1	Standard	Wood	30 to 35	$5.59	5,518	$370,147
3	Standard	Wood	40 to 55	$7.31	457	$40,088
11	Painted Underground	Wood	35	$5.59	94	$6,306
41	Curved laminated	Wood	30	$6.93	26	$2,162
31	Regular	Aluminum	16	$6.67	26	$2,081
32	Regular	Aluminum	25	$11.07	11	$1,461
33	Regular	Aluminum	30	$11.96	18	$2,583
28	Regular	Aluminum	35	$14.30	3	$515
65	Fluted Ornamental	Aluminum	14	$9.76	20	$2,342
18	Davit	Aluminum	25	$10.23	0	$0
6	Davit	Aluminum	30	$10.99	22	$2,901
29	Davit	Aluminum	35	$12.02	0	$0
70	Davit with 8-foot Arm	Aluminum	40	$16.30	0	$0
27	Double Davit	Aluminum	30	$16.22	3	$584
66	HADCO, Fluted Ornamental	Aluminum	16	$9.98	2	$240
69	HADCO, Non-fluted Techtra Ornamental	Aluminum	18	$19.21	19	$4,380
4	Ameron Post-Top	Concrete	25	$19.16	0	$0
63	Fluted Ornamental Black	Fiberglass	14	$11.81	177	$25,084
57	Regular Black	Fiberglass	20	$4.91	312	$18,383
61	Regular Gray	Fiberglass	30	$8.35	609	$61,022
68	Regular Other Colors	Fiberglass	35	$7.19	37	$3,192
16	Anchor Base Gray	Fiberglass	35	$13.11	2	$315
35	Direct Bury with Shroud	Fiberglass	18	$7.92	110	$10,454
79	Fluted Westbrooke	Aluminum	18	$19.26		
81	Non-Fluted Westbrooke	Aluminum	18	$20.41		
Totals					7,466	$554,241

Totals Luminaires and Poles $3,457,248