UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2016

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition period from ______ to ______

Commission File Number 001-05532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

121 S.W. Salmon Street
Portland, Oregon 97204
(503) 464-8000
(Address of principal executive offices, including zip code, and Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Common Stock, no par value	**New York Stock Exchange**
(Title of class)	(Name of exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [x] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.   Yes [ ]   No [x]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.   Yes [x]   No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Date File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).   Yes [x]   No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [x]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	[x]	Accelerated filer	[ ]
Non-accelerated filer	[ ]	Smaller reporting company	[ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).   Yes [ ]   No [x]

As of June 30, 2016, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $3,905,668,556. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 3, 2017, there were 88,946,932 shares of common stock outstanding.

Documents Incorporated by Reference

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the Annual Meeting of Shareholders to be held on April 26, 2017.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2016

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DEFINITIONS

The abbreviations or acronyms defined below are used throughout this Form 10-K:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
ARO	Asset retirement obligation
AUT	Annual Power Cost Update Tariff
Beaver	Beaver natural gas-fired generating plant
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal-fired generating plant
BPA	Bonneville Power Administration
CAA	Clean Air Act
Carty	Carty natural gas-fired generating plant
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
Coyote Springs	Coyote Springs Unit 1 natural gas-fired generating plant
CWIP	Construction work-in-progress
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
DEQ	Oregon Department of Environmental Quality
EFSA	Equity forward sale agreement
EPA	United States Environmental Protection Agency
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMB	First Mortgage Bond
FPA	Federal Power Act
GRC	General Rate Case for a specified test year
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
kV	Kilovolt = one thousand volts of electricity
Moody's	Moody's Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PW1	Port Westward Unit 1 natural gas-fired generating plant
PW2	Port Westward Unit 2 natural gas-fired flexible capacity generating plant
RPS	Renewable Portfolio Standard
S&P	S&P Global Ratings
SEC	United States Securities and Exchange Commission
Trojan	Trojan nuclear power plant
Tucannon River	Tucannon River Wind Farm
USDOE	United States Department of Energy

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company), a vertically integrated electric utility with corporate headquarters located in Portland, Oregon, is engaged in the generation, wholesale purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The Company operates as a cost-based, regulated electric utility with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers, and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE meets its retail load requirement with both Company-owned generation and power purchased in the wholesale market. The Company participates in the wholesale market through the purchase and sale of electricity and natural gas in an effort to obtain reasonably-priced power to serve its retail customers. PGE, incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange. The Company operates as a single business segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis.

PGE's state-approved service area allocation of approximately 4,000 square miles is located entirely within Oregon and includes 51 incorporated cities, of which Portland and Salem are the largest. The Company estimates that at the end of 2016 its service area population was 1.9 million, comprising approximately 46% of the population of the State of Oregon. During 2016, the Company added nearly 11,000 customers and as of December 31, 2016, served a total of 863,000 retail customers.

PGE had 2,752 employees as of December 31, 2016, with 783 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 730 and 53 employees and expire March 2020 and August 2017, respectively.

Available Information

PGE's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available and may be accessed free of charge through the Investors section of the Company's website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGE's website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K. Information may also be obtained via the SEC website at sec.gov.

Regulation

Federal and State of Oregon regulation both can have a significant impact on the operations of PGE. In addition to the agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1.

FERC and Other Federal Regulation

Several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC) have regulatory authority over certain of PGE's operations and activities, as described in the discussion that follows.

PGE is a "licensee," a "public utility," and a "user, owner, and operator of the bulk power system," as defined in the Federal Power Act (FPA). As such, the Company is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cyber security standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters.

Wholesale Energy—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA). The BAA is the area in which PGE is responsible for balancing customer demand with electricity generation, in real time. Continued market-based rate authority requires specific actions by PGE including the filing of triennial market power studies with the FERC, the filing of notices of change in status, and compliance with FERC rules. On June 30, 2016, PGE submitted its updated triennial market power analysis, which was supplemented in September, October, and again in December 2016. The FERC has yet to issue an order on this filing.

On August 26, 2016, PGE submitted a Notification of Change in Status for the addition of the Carty natural gas-fired generating plant (Carty). The addition of Carty resulted in PGE having over a 20% market share in its BAA, creating a presumption of market power within its BAA. PGE proposed, and the FERC accepted, that PGE will not make any future sales at market-based rates within its BAA. PGE can only make sales at cost based rates in its BAA. Historically, PGE has made very few sales of electric energy and ancillary services within its BAA. Given that and in light of current low market prices, PGE's inability to sell electric energy and ancillary services within its BAA at market-based rates is not expected to have a material impact on the Company.

Transmission—PGE offers electricity transmission service pursuant to its Open Access Transmission Tariff (OATT), which contains rates and terms and conditions of service, as filed with, and approved by the FERC. As required by the OATT, PGE provides information regarding its electric transmission business on its Open Access Same-time Information System, also known as OASIS. For additional information, see the Transmission and Distribution section in this Item 1. and Item 2.—"Properties."

Reliability and Cyber Security Standards—Pursuant to the Energy Policy Act of 2005, the FERC has adopted mandatory reliability standards for owners, users, and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of these standards. These standards include Critical Infrastructure Protection (CIP) standards, a set of cyber security standards that provide a framework to identify and protect critical cyber assets used to support reliable operation of the bulk power system. A new version of the NERC CIP standards came into effect July 1, 2016 that will require compliance by various dates through September 1, 2018.

There are certain FERC regulatory activities that PGE expects to undertake as part of its entry into the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM) including filing with the FERC both an updated OATT and a Readiness Criteria certification. The FERC requires this informational filing from PGE and the CAISO to declare that PGE has satisfied the CAISO's Readiness Criteria prior to PGE's starting EIM operations, which is planned for October 1, 2017. For further information on the EIM, see "Future Energy Resource Strategy" in the Power Supply section of this Item 1.

Natural Gas Pipelines—The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide the FERC authority in matters related to the construction, operation, extension, enlargement, safety, and abandonment of jurisdictional interstate natural gas pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in the Kelso-Beaver (KB) Pipeline, a 17-mile interstate pipeline that provides natural gas to the Company's natural gas-fired generating plants located near Clatskanie, Oregon: Port Westward Unit 1 (PW1); Port Westward Unit 2 (PW2); and Beaver. As the operator of record of the KB Pipeline, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety standards, operator qualification standards, and public awareness requirements.

Hydroelectric Licensing—Under the FPA, PGE's hydroelectric generating plants are subject to FERC licensing requirements, which include an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. PGE holds FERC licenses for the Company's projects on the Deschutes, Clackamas, and Willamette Rivers. For additional information, see the Environmental Matters section in this Item 1. and the Generating Facilities section in Item 2.—"Properties."

Accounting Policies and Practices—Pursuant to applicable provisions of the FPA, PGE prepares financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC.

Short-term Debt—Pursuant to applicable provisions of the FPA and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. The Company, pursuant to an order issued by the FERC on February 5, 2016, has authorization to issue up to $900 million of short-term debt through February 6, 2018.

Spent Fuel Storage—The NRC regulates the licensing and decommissioning of nuclear power plants, including PGE's Trojan nuclear power plant (Trojan), which was closed in 1993. The NRC approved the 2003 transfer of spent nuclear fuel from a spent fuel pool to a separately licensed dry cask storage facility that will house the fuel on the former plant site until a United States Department of Energy (USDOE) facility is available. Radiological decommissioning of the plant site was completed in 2004 under an NRC-approved plan, with the plant's operating license terminated in 2005. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site and radiological decommissioning of the storage facility is completed. For additional information on spent nuclear fuel storage activities, see Note 7, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

OPUC and Other State of Oregon Regulation

PGE is subject to the jurisdiction of the OPUC, and a number of other state agencies, as described in the discussion that follows.

The OPUC, which is comprised of three members appointed by the governor of Oregon to serve non-concurrent four-year terms, reviews and approves the Company's retail prices (see "*Economic Regulation*" below) and establishes conditions of utility service. In addition, the OPUC reviews the Company's generation and transmission resource acquisition plans, pursuant to a bi-annual integrated resource planning process. The OPUC regulates the issuance of securities, prescribes accounting policies and practices, regulates the sale of utility assets, reviews transactions with affiliated companies, and has jurisdiction over the acquisition of or exertion of substantial influence over public utilities. The OPUC also oversees the Retail Customer Choice Program and approves funding for Energy Efficiency, and establishes the public purpose charges that are remitted to the Energy Trust of Oregon (ETO).

Economic Regulation—Under Oregon law, the OPUC is required to ensure that prices and terms of service are fair, non-discriminatory, and provide regulated companies an opportunity to earn a reasonable return on their investments. Customer prices are determined through formal proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order. Participants in such proceedings, which are conducted under established procedural schedules, include PGE, OPUC staff, and intervenors representing PGE customer groups. The following are the more significant regulatory mechanisms and proceedings under which customer prices are determined.

- *General Rate Cases*. PGE periodically evaluates the need to change its retail electric price structure to sufficiently cover its operating costs and provide a reasonable rate of return to investors. Such changes are requested pursuant to a comprehensive general rate case process that includes revenue requirements based on a forecasted test year, debt-to-equity capital structure, return on equity, and overall rate of return. PGE plans to file a general rate case for the 2018 test year (2018 GRC) with the OPUC by the end of February

2017. Following a ten month public review process, the Company expects new prices to become effective in January 2018.

- *Power Costs*. In addition to price changes resulting from the general rate case process, the OPUC has approved the following mechanisms by which PGE can adjust retail customer prices to cover the Company’s net variable power costs (NVPC), which consist of the cost of purchased power and fuel used in generation (including related transportation costs) less revenues from wholesale power and fuel sales:
  - Annual Power Cost Update Tariff (AUT). Under this tariff, customer prices are adjusted annually to reflect the latest forecast of NVPC. An initial NVPC forecast, submitted to the OPUC by April 1st each year, is updated during such year and finalized in November. Based upon the final forecast, new prices, as approved by the OPUC, become effective at the beginning of the following calendar year; and
  - Power Cost Adjustment Mechanism (PCAM). Under the PCAM, PGE shares a portion of the business risk or benefit associated with NVPC. Customer prices can be adjusted annually to absorb a portion of the difference between the forecasted NVPC included in customer prices (baseline NVPC) and actual NVPC for the year. To the extent actual annual NVPC, subject to certain adjustments, is above or below the deadband, which is a defined range from $30 million above to $15 million below baseline NVPC, the PCAM provides for 90% of the variance beyond the deadband to be collected from or refunded to customers, respectively, subject to a regulated earnings test. A final determination of any customer collection or refund is made by the OPUC through a public filing and review, typically during the second half of the following year. Any estimated collection from customers pursuant to the PCAM is recorded as a reduction in Purchased power and fuel expense in the Company’s consolidated statements of income, while any estimated refund to customers is recorded as a reduction in Revenues, net. For additional information, see *“Power Operations”* in the Overview section in Item 7.—“Management’s Discussion and Analysis of Financial Condition and Results of Operations.” During the past three years, the Company has recorded no refunds or collections as a result of the PCAM.
- *Decoupling.* The decoupling mechanism provides a means for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts undertaken by residential and certain commercial customers. The mechanism, recently extended by the OPUC through 2019, provides for: i) collections from customers if weather adjusted energy use per customer is lower than levels anticipated in the Company’s most recent general rate case; or ii) refunds to customers if weather adjusted use per customer exceeds levels anticipated in the most recent general rate case. For additional information, see *“Customers and Demand”* in the Overview section in Item 7.—“Management’s Discussion and Analysis of Financial Condition and Results of Operations.”
- *Renewable Energy.* The 2007 Oregon Renewable Energy Act (the Act) established a Renewable Portfolio Standard (RPS), which required that PGE initially serve at least 5% of its retail load with renewable resources by 2011, with future requirements of 15% by 2015, 20% by 2020, and 25% by 2025. PGE met the 2011 and 2015 requirements and expects to meet requirements going forward.

  The Act also allows renewable energy credits, resulting from energy generated from qualified renewable resources placed in service after January 1, 1995, and certified low impact hydroelectric power resources, to be used to meet the Company’s RPS compliance obligation.

  The Act provides for the recovery in customer prices of prudently incurred costs required to comply with the RPS. Under a renewable adjustment clause (RAC) mechanism, PGE can recover the revenue requirement of new renewable resources and associated transmission that is not yet included in prices. Under the RAC, PGE may submit a filing by April 1st of each year for new renewable resources expected to be placed in service in the current year, with prices expected to become effective January 1st of the following year. In addition, the RAC provides for the deferral and subsequent recovery of eligible costs incurred prior to January 1st of the following year.

  The Company submitted a RAC filing to the OPUC in 2014 with the expectation that Tucannon River Wind Farm (Tucannon River) would be placed into service before the end of 2014. In 2015, PGE submitted a RAC filing to the OPUC related to a 1.2 MW solar facility with the expectation that it would be placed into service before the end of 2015. In March 2016, PGE submitted to the OPUC a RAC filing that requested no significant additions or deferrals for 2016.

The State of Oregon passed Senate Bill 1547, effective March 8, 2016, a law referred to as the Oregon Clean Electricity and Coal Transition Plan (OCEP). The legislation prevents large utilities from including the costs and benefits associated with coal-fired generation in their Oregon retail rates after 2030 (subject to an exception that extends this date until 2035 for the Company's output from the Colstrip Units 3 and 4 coal-fired generating plant (Colstrip)), increases the RPS percentages in certain future years, changes the life of certain renewable energy certificates (RECs), requires the development of community solar programs, seeks the development of transportation electrification programs, and requires that a portion of electricity come from small scale renewable or certain biomass projects.

Under Senate Bill 1547, PGE will be required to:

- meet RPS thresholds of 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040;
- limit the life of RECs generated from facilities that become operational after 2022 to five years, but maintain the unlimited lifespan of all existing RECs and allow for the generation of additional unlimited RECs for a period of five years for projects on line before December 31, 2022;
- include projected production tax credits (PTCs) in prices through any variable power cost forecasting process established by the OPUC, the first of which applied to the AUT filing for 2017; and
- include energy storage costs in its RAC filings.

The Company has evaluated the potential impacts and has incorporated the effects of the legislation into its 2016 Integrated Resource Plan (IRP), which was filed with the OPUC in the fourth quarter of 2016. In December 2016, the OPUC approved a tariff request submitted by PGE seeking approval to incorporate in customer prices on January 1, 2017 the estimated annual $6 million effect of accelerating recovery of the Colstrip facility from 2042 to 2030, which was required under the legislation.

As needed, other ratemaking proceedings may occur and can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific OPUC authorization. Such amounts are generally collected from, or refunded to, retail customers through the use of supplemental tariffs. For additional information on the RAC, the OCEP, and other ratemaking proceedings, see the *"Legal, Regulatory and Environmental Matters"* discussion in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Integrated Resource Plan—Unless the OPUC grants an extension, PGE is required to file an IRP with the OPUC within two years of its previous IRP acknowledgment order. The IRP guides the utility on a plan to meet future customer demand and describes the Company's future energy supply strategy, which reflects new technologies, market conditions, and regulatory requirements. The primary goal of the IRP is to identify a portfolio of generation, transmission, demand-side, and energy efficiency resources that, along with the Company's existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for PGE and its customers. For additional information on PGE's 2016 IRP, see *"Future Energy Resource Strategy"* in the Power Supply section in this Item 1.

Retail Customer Choice Program—PGE's commercial and industrial customers have access to pricing options other than cost-of-service, including direct access and daily market index-based pricing. All commercial and industrial customers are eligible for direct access, whereby customers purchase their electricity from an Electricity Service Supplier (ESS). Under the program, the Company is paid for delivery of the energy to the ESS customers. Large commercial and industrial customers may elect to be served by PGE on a daily market index-based price.

All non-residential retail customers have an option to be served by an ESS for a one-year period. Certain large commercial and industrial customers may elect to be removed from cost-of-service pricing for a fixed three-year or a minimum five-year term, to be served either by an ESS, or by the Company under a daily market index-based price. Participation in the fixed three-year and minimum five-year opt-out programs is capped at 300 average megawatts (MWa) in aggregate. The majority of the energy supplied under PGE's Retail Customer Choice program is provided to customers that have elected service from an ESS under the minimum five-year opt-out program.

ESSs have supplied direct access customers with energy representing 9% of the Company's total retail energy deliveries for each of the past three years. The maximum retail load allowed to be supplied under the fixed three-year and minimum five-year opt-out programs would represent approximately 14% of the Company's total retail energy deliveries for 2016, 2015, and 2014.

The retail customer choice program does not have a material impact on the Company's financial condition or operating results as revenue changes resulting from increases or decreases in electricity sales to direct access customers are substantially offset by changes in the Company's cost of purchased power and fuel. Further, the program provides for "transition adjustment" charges or credits to direct access and market-based pricing customers that reflect the above- or below-market cost of energy resources owned or purchased by the Company. Such adjustments are designed to ensure that the costs or benefits of the program do not unfairly shift to those customers that continue to purchase their energy requirements from the Company.

In addition to cost-of-service pricing, residential and small commercial customers can select portfolio options from PGE that include time-of-use and renewable resource pricing.

Energy Efficiency Funding—Oregon law provides for a "public purpose charge" to fund cost-effective energy efficiency measures, new renewable energy resources, and weatherization measures for low-income housing. This charge, equal to 3% of retail revenues, is collected from customers and remitted to the ETO and other agencies for administration of these programs. Approximately, $50 million was collected from customers for this charge in 2016, and $51 million in both 2015 and 2014.

In addition to the public purpose charge, PGE also remits to the ETO amounts collected from its customers under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. This charge was approximately 2.7%, 2.4%, and 3.2% of retail revenues for applicable customers in 2016, 2015, and 2014, respectively. Under the tariff, approximately $48 million, $42 million, and $48 million were collected from eligible customers in 2016, 2015, and 2014, respectively.

Siting—Oregon's Energy Facility Siting Council (EFSC) has regulatory and siting responsibility for large electric generating facilities, certain high voltage transmission lines, intrastate gas pipelines, and radioactive waste disposal sites. The responsibilities of the EFSC also include oversight of the decommissioning of Trojan. The seven volunteer members of the EFSC are appointed to four-year terms by the governor of Oregon, with staff support provided by the Oregon Department of Energy.

Regulatory Accounting

PGE is subject to accounting principles generally accepted in the United States of America (GAAP) and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. These principles provide for the deferral as regulatory assets of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and anticipated future regulatory environment and related accounting guidance. For additional information, see *“Regulatory Assets and Liabilities”* in Note 2, Summary of Significant Accounting Policies, and Note 6, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—“Financial Statements and Supplementary Data.”

Customers and Revenues

PGE generates revenue primarily through the sale and delivery of electricity to retail customers exclusively in Oregon within a service area approved by the OPUC. In addition, the Company distributes power to commercial and industrial customers that choose to purchase their energy supply from an ESS. The Company includes such “direct access” customers in its customer counts and energy delivered to such customers in its total retail energy deliveries. Retail revenues include only delivery charges and applicable transition adjustments for these direct access customers. The Company conducts retail electric operations within its service territory and competes with: i) the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances; and ii) fuel oil suppliers, primarily for residential customers’ space heating needs. Energy efficiency and conservation measures, as well as an increasing trend toward rooftop solar generation in recent years, also influence customer demand.

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 6% of PGE’s total retail revenues or 9% of total retail deliveries. While the twenty largest commercial and industrial customers constituted 11% of total retail revenues in 2016, they represented nine different groups including high tech, paper manufacturing, governmental agencies, health services, and retailers.

PGE's Retail revenues, retail energy deliveries, and average number of retail customers consist of the following for the years presented:

	Years Ended December 31,					
	2016		2015		2014	
Retail revenues[1] (dollars in millions):						
Residential	$ 907	51%	$ 895	50%	$ 893	51%
Commercial	665	37	662	37	657	36
Industrial	208	12	228	13	221	13
Subtotal	1,780	100	1,785	100	1,771	100
Other accrued (deferred) revenues, net	3	—	(10)	—	(8)	—
Total retail revenues	$ 1,783	100%	$ 1,775	100%	$ 1,763	100%
Retail energy deliveries[2] (MWh in thousands):						
Residential	7,348	39%	7,325	38%	7,462	39%
Commercial	7,457	39	7,511	39	7,494	39
Industrial	4,166	22	4,546	23	4,310	22
Total retail energy deliveries	18,971	100%	19,382	100%	19,266	100%
Average number of retail customers:						
Residential	752,365	88%	742,467	88%	735,502	87%
Commercial	106,773	12	105,802	12	105,231	13
Industrial	258	—	255	—	260	—
Total	859,396	100%	848,524	100%	840,993	100%

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.
(2) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

Additional averages for retail customers are as follows:

	Years Ended December 31,		
	2016	2015	2014
Residential			
Revenue per customer (in dollars):	$ 1,114	$ 1,139	$ 1,154
Usage per customer (in kilowatt hours):	9,766	9,866	10,145
Revenue per kilowatt hour (in cents):	11.40¢	11.55¢	11.37¢
Commercial			
Revenue per customer (in dollars):	$ 6,166	$ 6,254	$ 6,187
Usage per customer (in kilowatt hours):	69,839	70,987	71,216
Revenue per kilowatt hour (in cents):	8.83¢	8.81¢	8.69¢
Industrial			
Revenue per customer (in dollars):	$ 804,953	$ 876,866	$ 851,149
Usage per customer (in kilowatt hours):	16,146,371	17,485,281	16,576,500
Revenue per kilowatt hour (in cents):	4.99¢	5.01¢	5.13¢

For additional information, see the Results of Operations section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

In accordance with state regulations, PGE's retail customer prices are based on the Company's cost of service and are determined through general rate case proceedings and various tariff filings with the OPUC. Additionally, the Company offers different pricing options including a daily market price option, various time-of-use options, and several renewable energy options, which are offered to residential and small commercial customers. For additional information on customer options, see "*Retail Customer Choice Program*" within the Regulation section of this Item 1. Additional information on the customer classes follows.

Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of weather, with demand historically highest during the winter heating season; although, increased use of air conditioning in PGE's service territory has caused the summer peaks to increase in recent years and long-term load forecasts show summer peaks to exceed winter peaks. Economic conditions can also affect residential demand; strong job growth and population growth in PGE's service territory have led to increasing customer growth rates. Residential demand is also impacted by energy efficiency measures; however, the Company's decoupling mechanism is intended to mitigate the financial effects of such measures.

During 2016, total residential deliveries increased 0.3% compared to 2015. Although PGE witnessed a 1.3% increase in the average number of residential customers served during the year, actual usage per customer declined by 1.0% driven by unfavorable weather compared to the prior year. Both 2015 and 2016 experienced historically warm temperatures during the winter heating season, reducing residential energy deliveries; however, 2016 did not experience the offsetting warm temperatures during the cooling season that were experienced in 2015. On a weather adjusted basis, energy deliveries to residential customers increased by 1.4% in 2016 when compared to 2015.

During 2015, PGE experienced historically warm temperatures during the winter heating season reducing residential energy deliveries. Although this weather effect was partially offset by warm temperatures during the summer cooling season, the overall result was that total residential deliveries decreased 1.8% in 2015 compared to 2014. On a weather adjusted basis, energy deliveries to residential customers increased by 2.2% in 2015 when compared to 2014.

Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class includes most businesses, small industrial companies, and public street and highway lighting accounts.

The Company's commercial customers are somewhat less susceptible to weather conditions than the residential customer, although weather does have an effect on commercial demand. Economic conditions and fluctuations in total employment in the region can also lead to changes in energy demand from commercial customers. Commercial demand is also impacted by energy efficiency measures, the financial effects of which are partially mitigated by the Company's decoupling mechanism.

In 2016, despite 0.9% growth in the average number of commercial customers, commercial deliveries decreased 0.7% compared with 2015. The decrease reflects unfavorable weather conditions, and slightly lower demand from a few groups, including food stores, which were impacted by a series of mergers and bankruptcies, government and education, and irrigation and pumping load in 2016 due to the extremely dry conditions that existed in 2015. On a weather adjusted basis, commercial deliveries for 2016 were comparable to 2015. Energy efficiency continues to impact growth, and conservation and building codes and standards are likely reducing energy deliveries beyond the impact of energy efficiency programs.

Deliveries to commercial customers increased 0.2% in 2015 compared with 2014, which was primarily due to an increase in deliveries to irrigation and service sector customers being mostly offset by lower deliveries to all other commercial sectors combined with a 1.0% increase in the average number of commercial customers.

Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered on the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class.

The Company’s industrial energy deliveries decreased 8.4% in 2016 from 2015, largely due to a large paper manufacturing customer, to which PGE has delivered approximately 450 thousand MWhs annually, with corresponding revenues of approximately $20 million, having ceased operations in late 2015. Although the majority of power this customer purchased was under the Company’s daily market index-based price option, a portion was at cost of service prices. Adjusted for that one customer, industrial energy deliveries were 1.4% higher than 2015 levels driven by continued, albeit slowed, increases in energy deliveries to high tech manufacturing customers.

The 5.5% increase in 2015 from 2014 was due primarily to increased demand from high tech manufacturing and paper manufacturing customers.

Other accrued (deferred) revenues, net include items that are not currently in customer prices, but are expected to be in prices in a future period. Such amounts include, among other things, deferrals recorded under the RAC and the decoupling mechanism. For further information on these items, see “*OPUC and Other State of Oregon Regulation*” in the Regulation section of this Item 1.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, hydro and wind conditions, and daily and seasonal retail demand. Wholesale revenues represented 5% of total revenues in 2016, 2015, and 2014.

The majority of PGE’s wholesale electricity sales is to utilities and power marketers and is predominantly short-term. The Company may choose to net its purchases and sales with the same counterparty rather than simultaneously receiving and delivering physical power; in such cases, only the net amount of those purchases or sales required to meet retail and wholesale obligations will be physically settled.

Other Operating Revenues

Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Company’s generating facilities, as well as revenues from transmission services, excess transmission capacity resales, excess fuel sales, pole contact rentals, and other electric services provided to customers. Other operating revenues have represented 2% of total revenues in each of the past three years.

Seasonality

Demand for electricity by PGE’s residential and, to a lesser extent, commercial customers, is affected by seasonal weather conditions. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days provide cumulative variances in the average daily temperature from a baseline of 65 degrees, over a period of time, to indicate the extent to which customers are likely to use, or have used, electricity for heating or air conditioning. The higher the number of degree-days, the greater the expected demand for electricity.

The following table presents the heating and cooling degree-days for the most recent three-year period, along with 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days	Cooling Degree-Days
2016	3,552	548
2015	3,461	785
2014	3,794	653
15-year average	4,233	471

PGE's all-time high net system load peak of 4,073 megawatts (MW) occurred in December 1998. The Company's all-time "summer peak" of 3,949 MW occurred in July 2009. The following table presents PGE's average winter (defined as January, February, and December) and summer (defined as July, August, and September) loads for the periods presented, along with the corresponding peak load (in MWs) and month in which such peak occurred:

	Winter Loads			Summer Loads		
	Average	**Peak**	**Month**	**Average**	**Peak**	**Month**
2016	2,537	3,716	December	2,246	3,726	August
2015	2,509	3,255	December	2,390	3,914	July
2014	2,574	3,866	February	2,358	3,646	August

The Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting, integrated resource planning, and preparing general rate case assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company will need to adequately meet those loads and maintain adequate capacity reserves.

Power Supply

PGE relies upon its generating resources, as well as wholesale power purchases from third parties to meet its customers' energy requirements. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources and the price and availability of wholesale power and natural gas. As part of its power supply operations, the Company enters into short- and long-term power and fuel purchase agreements. PGE executes economic dispatch decisions concerning its own generation, and participates in the wholesale market in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. The Company also promotes energy efficiency measures to meet its energy requirements.

PGE's generating resources consist of seven thermal plants (natural gas- and coal-fired), two wind farms, and seven hydroelectric facilities. Capacity of the thermal plants represents the MW the plant is capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant. Capacity of both hydro and wind generating resources represent the nameplate MW, which varies from actual energy expected to be received as these types of generating resources are highly dependent upon river flows and wind conditions, respectively. Availability represents the percentage of the year the plant was available for operations, which reflects the impact of planned and forced outages. For a complete listing of these facilities, see "*Generating Facilities*" in Item 2.—"Properties."

PGE's resource capacity (in MW) was as follows:

	As of December 31,					
	2016		2015		2014	
	Capacity	%	Capacity	%	Capacity	%
Generation:						
Thermal:						
Natural gas	1,805	38%	1,371	30%	1,389	28%
Coal	814	17	814	17	814	17
Total thermal	2,619	55	2,185	47	2,203	45
Wind (1)	717	15	717	16	717	15
Hydro (2)	495	11	495	11	494	10
Total generation	3,831	81	3,397	74	3,414	70
Purchased power:						
Long-term contracts:						
Capacity/exchange	250	5	250	5	250	5
Hydro	534	12	592	13	595	12
Wind	39	1	39	1	39	1
Solar	13	—	13	—	13	—
Other	18	—	118	3	118	2
Total long-term contracts	854	18	1,012	22	1,015	20
Short-term contracts	45	1	200	4	481	10
Total purchased power	899	19	1,212	26	1,496	30
Total resource capacity	4,730	100%	4,609	100%	4,910	100%

(1) Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 215 MWa to 290 MWa, dependent upon wind conditions.
(2) Capacity represents net capacity and differs from expected energy to be generated, which is expected to range from 200 MWa to 250 MWa, dependent upon river flows.

For information regarding actual generating output and purchases for the years ended December 31, 2016, 2015, and 2014, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

The portion of PGE's retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and unplanned outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability. In July 2016, PGE placed Carty, a natural gas-fired baseload resource, into service and in December 2014, completed construction of PW2, a flexible capacity resource, and Tucannon River, a wind resource. These additional resources resulted from the competitive bidding process completed in 2013 consistent with the Company's 2009 IRP. For additional information on the completion of Carty, see "*Carty*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Thermal The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty. These natural gas-fired generating plants provided approximately 32% of PGE's total retail load requirement in 2016, 25% in 2015, and 18% 2014.

PGE increased its ownership interest in the Boardman coal-fired generating plant (Boardman) through the acquisition of the 10% interest of a co-owner, increasing the Company's ownership share to 90% from 80% on December 31, 2014.

The Company operates Boardman and has a 20% ownership interest in Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is operated by a third party. These two coal-fired generating facilities provided approximately 19% of the Company's total retail load requirement in 2016, compared with 22% in 2015, and 24% in 2014. Boardman is scheduled to cease coal-fired operations at the end of 2020, and pursuant to Oregon Senate Bill 1547, PGE's portion of Colstrip is scheduled to be fully depreciated by 2030, with the potential to utilize the output of the facility, in Oregon, until 2035. For additional information on Senate Bill 1547, see "*Legal, Regulatory and Environmental Matters*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

The thermal plants provide reliable power and capacity reserves for PGE's customers. These resources have a combined capacity, with the addition of Carty, of 2,619 MW, representing approximately 68% of the net capacity of PGE's generating portfolio. Thermal plant availability, excluding Colstrip, was 92% in 2016 and 89% in both 2015 and 2014, while Colstrip availability was 85% in 2016, compared with 93% in 2015 and 83% in 2014.

Wind PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River. Biglow Canyon, located in Sherman County, Oregon, is PGE's largest renewable energy resource consisting of 217 wind turbines with a total nameplate capacity of approximately 450 MW. Tucannon River, placed in service in December 2014, is located in southeastern Washington and consists of 116 wind turbines with a total nameplate capacity of 267 MW.

The energy from wind resources provided 10% of the Company's total retail load requirement in 2016, 9% in 2015, and 6% in 2014. Availability for these resources was 95% in 2016, compared with 97% in 2015 and 94% in 2014. The expected energy from wind resources differs from the nameplate capacity and is expected to range from 135 MWa to 180 MWa for Biglow Canyon and from 80 MWa to 110 MWa for Tucannon River, dependent upon wind conditions.

Hydro The Company's FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. The licenses for these projects expire at various dates ranging from 2035 to 2055. Although these plants have a combined capacity of 495 MW, actual energy received is dependent upon river flows. Energy from these resources provided 9% of the Company's total retail load requirement in 2016, 8% in 2015, and 9% in 2014, with availability of 99% in both 2016 and 2015, and 100% in 2014. Northwest hydro conditions have a significant impact on the region's power supply, with water conditions significantly impacting PGE's cost of power and its ability to economically displace more expensive thermal generation and spot market power purchases.

PGE has a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The Tribes have an option to purchase an additional undivided 16.66% interest in Pelton/Round Butte at its discretion on December 31, 2021. The Tribes have a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If both options are exercised by the Tribes, the Tribes' ownership percentage would exceed 50%.

Dispatchable Standby Generation (DSG)—PGE has a DSG program under which the Company can start, operate, and monitor customer-owned diesel-fueled standby generators when needed to provide NERC-required operating reserves. As of December 31, 2016, there were 58 sites with a total DSG capacity of 117 MW. Additional DSG projects are being pursued with a total goal of 135 MW online by the end of 2021.

Fuel Supply—PGE contracts for natural gas and coal supplies required to fuel the Company's thermal generating plants, with certain plants also able to operate on fuel oil if needed. In addition, the Company uses forward, future, swap, and option contracts to manage its exposure to volatility in natural gas prices.

Natural Gas Physical supplies of natural gas are generally purchased up to twelve months in advance of delivery and based on anticipated operation of the plants. PGE attempts to manage the price risk of natural gas supply through the use of financial contracts up to 60 months in advance of expected need of energy.

PGE owns 79.5%, and is the operator of record, of the Kelso-Beaver Pipeline, which directly connects PW1, PW2, and Beaver to Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports natural gas on the Kelso-Beaver Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 103,305 Dth per day of firm natural gas transportation capacity to serve the three plants.

PGE also has contractual access to natural gas storage in Mist, Oregon from which it can draw as needed. The Company expects to utilize this resource when economic factors favor its use or in the event that natural gas supplies are interrupted. The storage facility is owned and operated by a local natural gas company, NW Natural, and may be utilized to provide fuel to PW1, PW2, and Beaver. PGE has entered into a long-term agreement with this gas company to expand the current storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-mile pipeline, that will be designed to provide no-notice storage services to these PGE generating plants. Pursuant to the agreement, on September 30, 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which NW Natural estimates will be completed during the winter of 2018-2019, at a cost of approximately $128 million.

Beaver has the capability to operate on No. 2 diesel fuel oil when it is economical or if the plant's natural gas supply is interrupted. PGE had an approximate four day supply of ultra-low sulfur diesel fuel oil at the plant site as of December 31, 2016. The current operating permit for Beaver limits the number of gallons of fuel oil that can be burned daily, which effectively limits the daily hours of operation of Beaver on fuel oil.

To serve Coyote Springs and Carty, PGE has access to 119,500 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. PGE believes that sufficient market supplies of natural gas are available for Coyote Springs and Carty for the foreseeable future, based on anticipated operation of the plants. Although Coyote Springs was designed to also operate on fuel oil, such capability has been deactivated in order to optimize natural gas operations.

Coal PGE has fixed-price purchase agreements that, together with existing inventory, will provide coal sufficient for the anticipated operating needs for Boardman during 2017. The coal is obtained from surface mining operations in Wyoming and Montana and is delivered by rail under two separate transportation contracts which extend through 2020.

The terms of contracts and the quality of coal are expected to be staged in alignment with required emissions limits. PGE believes that sufficient market supplies of coal are available to meet anticipated operations of Boardman through 2020.

The Colstrip co-owners currently obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility. The current contract for coal supply extends through 2019 and the Colstrip co-owners are in the process of negotiating an extension to the contract.

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis. Such contracts have original terms ranging from one month to 53 years and expire at varying dates through 2055.

PGE's medium term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel.

The Company's major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts):

Capacity/exchange—PGE has two contracts that provide PGE with firm capacity to help meet the Company's peak loads. The contracts represent two power purchase agreements for up to 100 MW of seasonal peaking capacity, one agreement covers winter from December 2014 to February 2019 and the second agreement covers summer from July 2014 to September 2018. During 2016, PGE also had one contract representing 150 MW of capacity which expired in December 2016.

Hydro—During 2016, the Company had four contracts that provided for the purchase of power generated from hydroelectric projects with an aggregate capacity of 59 MW and contract expirations between 2017 and 2033. In addition, PGE has the following:

- *Mid-Columbia hydro*—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington for a portion of the output of three hydroelectric projects on the mid-Columbia River. One contract representing 150 MW of capacity expires in 2018 and a contract representing 163 MW of capacity expires in 2052. Although the projects currently provide a total of 313 MW of capacity, actual energy received is dependent upon river flows and capacity amounts may decline over time.
- *Confederated Tribes*—PGE has a long-term agreement under which the Company purchases, at index prices, the Tribes' interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 162 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. In 2014, PGE entered into an agreement with the Tribes under which the Tribes have agreed to sell, on modified payment terms, their share of the energy generated from the Pelton/Round Butte hydroelectric project exclusively to the Company through 2024.

Wind—PGE has three contracts that provide for the purchase of renewable wind-generated electricity and which extend to various dates between 2028 and 2035. The expected energy from these wind contracts differs from the nameplate capacity and is expected to approximate 39 MWa, dependent upon wind conditions.

Solar—PGE has three agreements that expire during 2036 and 2037 to purchase power generated from photovoltaic solar projects, which have a combined generating capacity of 7 MW. In addition, the Company operates, and purchases power from three solar projects with an aggregate of approximately 6 MW of capacity. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions.

Other—These primarily consist of long-term contracts to purchase power from various counterparties, including other Pacific Northwest utilities, over terms extending into 2031.

Short-term contracts—These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Company's load requirements.

PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 15 minutes to less than one month. For additional information regarding PGE's power purchase contracts, see Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Future Energy Resource Strategy

PGE's IRP outlines how the Company proposes to meet future customer demand and describes PGE's future energy supply strategy. The Company's IRP filing acknowledged by the OPUC in December 2014, and updated in December 2015, included an "Action Plan" that covered PGE's proposed actions to occur before the end of 2017. As a result, in September 2015, the Company announced plans to explore participation in the western EIM, which was launched in 2014 by the CAISO. The western EIM is a real-time energy wholesale market that automatically dispatches the lowest-cost electricity resources available to meet utility customer needs, while optimizing use of renewable energy over a large geographic area. PGE signed an agreement, which was approved by the FERC in January 2016, to join the western EIM. The agreement outlines a schedule of activities and milestones leading to the Company's participation in the EIM, targeted to begin in the fall of 2017.

PGE filed a subsequent IRP (2016 IRP) with the OPUC in mid- November 2016. The 2016 IRP addresses acquisition of additional resources to meet RPS requirements and replace energy and capacity from Boardman, which will cease coal-fired operations at the end of 2020. Further actions identified through 2021 are expected to offset expiring power purchase agreements and integrate variable energy resources, such as wind or solar generation facilities. The 2016 IRP also considers the OCEP, which, among other things, increased the RPS requirements for 2025 and future years. For further information on the OCEP, see the *"Legal, Regulatory and Environmental"* section of in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

All portfolios analyzed in the 2016 IRP pursue: i) compliance with the RPS through 2050; ii) inclusion of cost-effective customer-side options, including energy efficiency, demand response, conservation voltage reduction, and dispatchable standby generation; and iii) retention of all existing power plants until 2050, with the exception of Boardman and Colstrip Units 3 & 4.

The 2016 IRP is available on PGE's website. The recommended Action Plan in the 2016 IRP encompasses both demand-side and supply-side actions as well as integration through flexible technologies. Specific recommendations include: i) the deployment of a minimum of 135 MWa of cost-effective energy efficiency; ii) the pursuit of up to 77 MW of additional demand response; and iii) the addition of approximately 175 MWa in RPS compliant renewable resources, which could include unbundled RECs. The current draft also identifies the need for PGE to acquire up to 850 MW of capacity, which includes 375-550 MW of long-term dispatchable resources and up to 400 MW of annual capacity resources.

Acknowledgment of the 2016 IRP is targeted for mid-2017. Upon acknowledgment, PGE will request approval from the OPUC to issue one or more RFPs to acquire capacity and renewable resources through a combination of resource options that could include wind, solar, geothermal, biomass, efficient combined-cycle natural gas-fired facilities, and generic capacity facilities such as seasonal contracts, power purchase agreements, energy storage, and combustion turbines. The RFP process will include oversight by an independent evaluator and review by the OPUC.

Transmission and Distribution

Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one balancing authority area (an electric system bounded by interchange metering) in its service territory. In 2016, PGE delivered approximately 22 million megawatt hours (MWh) in its balancing authority area through 1,248 circuit miles of transmission lines operating at or above 115 kV.

PGE's transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with Bonneville Power Administration (BPA) to transmit a significant amount of the Company's generation to serve its distribution system. PGE's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers' energy requirements. PGE's generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency.

The Company's transmission and distribution systems are generally located as follows:

- On property owned or leased by PGE;
- Under or over streets, alleys, highways and other public places, the public domain and national forests, and federal and state lands primarily under franchises, easements or other rights that are generally subject to termination;
- Under or over private property primarily pursuant to easements obtained from the record holder of title at the time of grant; and
- Under or over Native American reservations under grant of easement by the Secretary of the Interior or lease or easement by Native American tribes.

The Company's wholesale transmission activities are regulated by the FERC and are offered on a non-discriminatory basis, with all potential customers provided equal access to PGE's transmission system through PGE's OATT. In accordance with its OATT, PGE offers several transmission services to wholesale customers:

- Network integration transmission service, a service that integrates generating resources to serve retail loads;
- Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and
- Non-firm point-to-point service, an "as available" service with fixed delivery and receipt points.

PGE is subject to state regulatory requirements related to the quality and reliability of its distribution system. Such requirements are reflected in specific indices that measure outage duration, outage frequency, and momentary power interruptions. The Company is required to include performance results related to service quality measures in annual reports filed with the OPUC.

For additional information regarding the Company's transmission and distribution facilities, see "*Transmission and Distribution*" in Item 2.—"Properties."

Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous material. Various state and federal agencies regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, clean-up, and disposal of toxic and hazardous substances. In addition, certain of the Company's hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain regulations that affect the Company's operations and facilities.

Air Quality

Clean Air Act—PGE's operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses, among other things, particulate matter, hazardous air pollutants, and greenhouse gas emissions (GHGs). Oregon and Montana, the states in which PGE's thermal facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least equal to federal standards.

The EPA issued a rule effective in April 2012, aimed at the reduction of toxic air emissions from power plants. Specifically, these mercury and air toxics standards (MATS) are intended to reduce emissions from new and existing coal- and oil-fired electric utility steam generating units. Existing emissions controls at Boardman and Colstrip allow the plants to meet the MATS requirements without additional capital investment. Oregon Department of Environmental Quality (DEQ) rules provide for coal-fired operation at Boardman to cease no later than December 31, 2020. The Company does not anticipate further capital investment to meet the requirements currently in place.

Although regulation of mercury emissions is contemplated under MATS, the states of Oregon and Montana have previously adopted regulations concerning mercury emissions, with which the Company complies.

PGE manages its air emissions by the use of low sulfur fuel, emissions and combustion controls and monitoring, and sulfur dioxide (SO_2) allowances awarded under the CAA. The current and expected future SO_2 allowances, along with the recent installation of emissions controls and the continued use of low sulfur fuel, are anticipated to be sufficient to permit the Company to meet its air emissions compliance requirements.

Climate Change—The EPA has taken the lead role on climate change policy utilizing existing authority under the CAA to develop regulations. In August 2015, the EPA released a final rule, which it calls the "Clean Power Plan." Under the final rule, each state would have to reduce the carbon intensity of its power sector on a state-wide basis by an amount specified by the EPA. The rule establishes state-specific goals in terms of pounds of carbon dioxide emitted per MWh of energy produced. The rule is intended to result in a reduction of carbon emissions from existing power plants across all states to approximately 32% below 2005 levels by 2030.

The target amounts were determined based on the EPA's view of the options for each state, including: i) making efficiency upgrades at fossil fuel-fired power plants; ii) shifting generation from coal-fired plants to natural gas-fired plants; and iii) expanding use of zero- and low-carbon emitting generation (such as renewable energy and nuclear energy). The final goal would need to be met by 2030 and interim goals for each state would need to be met from 2022 to 2029. Under the rule, states have flexibility in designing programs to meet their emission reduction targets, including the three approaches noted above and any other measures the states choose to adopt (such as carbon tax and cap-and-trade) that would result in verified emission reductions.

PGE cannot predict how the states in which the Company's generation facilities are located (Oregon and Montana) will implement the rule or how the rule may impact the Company's operations. The Company continues to monitor the developments around the implementation of the rule and efforts by state regulators to develop state plans. On February 9, 2016, the United States Supreme Court granted a stay, halting implementation and enforcement of the Clean Power Plan pending the resolution of legal challenges to the rule. The Company cannot predict the impact of the stay, the ultimate outcome of the legal challenges, or whether Oregon will continue to develop the state's implementation plan in light of the Supreme Court's stay.

The State of Oregon established a non-binding policy guideline that sets a goal to reduce GHG emissions to 10% below 1990 levels by 2020 and at least 75% below 1990 levels by 2050. Although the guideline does not mandate reductions by any specific entity, nor include penalties for failure to meet the goal, the Company is required to report to the DEQ the amount of GHG emissions produced along with the total amount of energy produced or purchased by PGE for consumption in Oregon.

Any laws that would impose emissions taxes or mandatory reductions in GHG emissions may have a material impact on PGE's operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. PGE's natural gas-fired facilities, Beaver, Coyote Springs, PW1, and PW2, Carty, and the Company's ownership interest in coal-fired facilities, Boardman and Colstrip, provided, in total, approximately 68% of the Company's net generating capacity at December 31, 2016. If PGE were to incur incremental costs as a result of changes in the regulations regarding GHGs, the Company would seek recovery in customer prices.

Oregon Clean Electricity and Coal Transition Plan—The State of Oregon passed Senate Bill 1547, effective March 8, 2016. The legislation prevents large utilities from including the costs and benefits associated with coal-fired generation in their Oregon retail rates after 2030 (subject to an exception that extends this date until 2035 for PGE's output from the Colstrip facility), increases the RPS percentages in certain future years, changes the life of certain RECs, requires the development of community solar programs, seeks the development of transportation electrification programs, and requires that a portion of electricity come from small scale renewable or certain biomass projects. For more information regarding the OCEP, and its impact on PGE, see the "*Legal, Regulatory and Environmental Matters*" section of Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations.

Water Quality

The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification from the state in which the activity will occur. In Oregon, Montana, and Washington, the Departments of Environmental Quality are responsible for reviewing proposed projects under this requirement to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits where required, and has certificates of compliance for its hydroelectric operations under the FERC licenses.

Threatened and Endangered Species and Wildlife

Fish Protection—The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest that have declined significantly over the last several decades. Long-term recovery plans for these species continue to have operational impacts on many of the region's hydroelectric projects. PGE purchases power in the wholesale market to serve its retail load requirements and has contracts to purchase power generated at some of the affected facilities on the mid-Columbia River in central Washington. In addition, the Company purchases power in the wholesale energy market, some of which is sourced from other affected hydroelectric facilities in the Pacific Northwest.

PGE continues to implement fish protection measures at its hydroelectric projects on the Clackamas, Deschutes, and Willamette rivers that were prescribed by the U.S. Fish and Wildlife Service (USFWS) and the National Marine Fisheries Service under their authority granted in the ESA and the FPA. As a result of measures contained in their operating licenses, the Deschutes River and Willamette River projects have been certified as low impact hydro, with 50 MWa of output from those facilities included as part of the Company's renewable energy portfolio used to meet the requirements of the Oregon RPS. Conditions required with the operating licenses are expected to result in a minor reduction in power production and continued capital spending to modify the facilities to enhance fish passage and survival.

Avian Protection—Various statutes, including the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act, contain provisions for civil, criminal, and administrative penalties resulting from the unauthorized take of migratory birds and eagles. Because PGE operates facilities that can pose risks to a variety of such birds, the Company developed an avian protection plan to help address and reduce risks to bird species that may be affected by Company operations. PGE has implemented such a plan for its transmission, distribution, and thermal generation facilities and continues to finalize similar plans, for its wind generation facilities. In 2015, PGE submitted an application, along with a draft Eagle Conservation Plan, to the USFWS, pertaining to Biglow Canyon that would address the incidental take of eagles, and expects to submit a similar application for Tucannon River in 2017.

Hazardous Waste

PGE has a comprehensive program to comply with requirements of both federal and state regulations related to the storage, handling, and disposal of hazardous waste. The handling and disposal of hazardous waste from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act (RCRA). In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act.

The generation of electricity at Boardman and Colstrip produces a by-product known as coal combustion residuals (CCRs), which have historically not been considered hazardous waste under the RCRA. In December 2014, the EPA signed a final rule, which became effective as of October 19, 2015, to regulate CCRs under the RCRA. Boardman produces dry CCRs that have historically been disposed at an on-site landfill, which is permitted and regulated by the State of Oregon under requirements similar to the new EPA rule. PGE has determined that it will continue use of the on-site landfill in compliance with the new rule, and the Company believes the new EPA rule will not have a material effect on operations at Boardman. Based on information from the Colstrip operator, this rule will have an effect on operations at Colstrip, which produces wet CCRs, and as a result, in 2015 PGE updated its Asset Retirement Obligation and adjusted its cost assumptions, accordingly. For further information, see Note 2, Summary of Significant Accounting Policies and *"Utility plant"* in Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), commonly referred to as Superfund, which provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites.

A 1997 investigation by the EPA, of a segment of the Willamette River in Oregon known as Portland Harbor, revealed significant contamination of river sediments and prompted the EPA to subsequently include Portland Harbor on the federal National Priority List as a Superfund site. The EPA has listed PGE among the more than one hundred Potentially Responsible Parties (PRPs) in this matter, as PGE has historically owned or operated property near the river.

On January 6, 2017, the EPA issued a Record of Decision (ROD), which outlines the EPA's selected remediation alternative to clean-up for Portland Harbor. The estimated total cost of the remedy has a discounted present value of $1.05 billion with an estimated remediation period of 13 years. PGE is participating in a voluntary process to determine an appropriate allocation of costs amongst the PRPs. Significant uncertainties remain surrounding facts and circumstances that are integral to the determination of such an allocation percentage, including a final allocation methodology and data with regard to property specific activities and history of ownership of sites within Portland Harbor. Based on the above facts and remaining uncertainties, PGE cannot reasonably estimate its potential liability.

On July 15, 2016, the Company filed a deferral application with the OPUC to allow for the deferral of the future environmental remediation costs related to Portland Harbor, as well as seek authorization to establish a regulatory cost recovery mechanism for such environmental costs. The Company has reached an agreement with OPUC Staff and other parties regarding the details of the recovery mechanism, subject to OPUC final decision, which is expected in the first quarter of 2017. The mechanism, as proposed, would allow the Company to recover incurred environmental expenditures through a combination of third-party proceeds, such as insurance recoveries, and through customer prices, as necessary. The mechanism would establish annual prudency reviews of environmental expenditures and be subject to an annual earnings test. For additional information on this EPA action, see Note 17, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Under the Nuclear Waste Policy Act of 1982, the USDOE is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel at the former plant site. The spent nuclear fuel is expected to remain in the ISFSI until permanent off-site storage is available. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2034. For additional information regarding this matter, see "*Trojan decommissioning activities*" in Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

ITEM 1A. RISK FACTORS.

Certain risks and uncertainties that could have a significant impact on PGE's business, financial condition, results of operations, or cash flows, or that may cause the Company's actual results to vary materially from the forward-looking statements contained in this Annual Report on Form 10-K, include those set forth below.

Recovery of PGE's costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect the Company's results of operations.

The prices that PGE charges for its retail services, as authorized by the OPUC, are a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. As a general matter, PGE seeks to recover in customer prices most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements and the costs of damage from storms and other natural disasters. However, there can be no assurance that such recovery will be granted. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

PGE attempts to manage its costs at levels consistent with the OPUC approved prices. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Company's financial and operating results could be adversely affected.

Economic conditions that result in reduced demand for electricity and impair the financial stability of some of PGE's customers, could affect the Company's results of operations.

Unfavorable economic conditions in Oregon may result in reduced demand for electricity. Such reductions in demand could adversely affect PGE's results of operations and cash flows. Economic conditions could also result in an increased level of uncollectible customer accounts and cause the Company's vendors and service providers to experience cash flow problems and be unable to perform under existing or future contracts.

Market prices for power and natural gas are subject to forces that are often not predictable and which can result in price volatility and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply, which ultimately could have an adverse effect on the Company's liquidity and results of operations.

As part of its normal business operations, PGE purchases power and natural gas in the open market under short- and long-term contracts, which may specify variable prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology.

Volatility in these markets can affect the availability, price and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGE's ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Company's existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Company's liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated.

The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices.

The effects of weather on electricity usage can adversely affect results of operations.

Weather conditions can adversely affect PGE's revenues and costs, impacting the Company's results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winters or cooler-than-normal summers reducing the demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Severe weather can also disrupt energy delivery and damage the Company's transmission and distribution system.

Rapid increases in load requirements resulting from unexpected adverse weather changes, particularly if coupled with transmission constraints, could adversely impact PGE's cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices.

Forced outages at PGE's generating plants can increase the cost of power required to serve customers because the cost of replacement power purchased in the wholesale market generally exceeds the Company's cost of generation.

Forced outages at the Company's generating plants could result in power costs greater than those included in customer prices. As indicated above, application of the Company's PCAM could help mitigate adverse financial impacts of such outages; however, the cost sharing features of the mechanism do not provide full recovery in customer prices. Inability to recover such costs in future prices could have a negative impact on the Company's results of operations.

The construction of new facilities, or modifications to existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs.

PGE supplements its own generation with wholesale power purchases to meet its retail load requirement. In addition, long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGE's generation, transmission, and distribution systems. Construction of new facilities and modifications to existing facilities could be affected by various factors, including unanticipated delays and cost increases and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities, which could result in failure to complete the projects and the disallowance of certain costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

Adverse changes in PGE's credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds.

Access to capital markets is important to PGE's ability to operate its business and complete its capital projects. Credit rating agencies evaluate the Company's credit ratings on a periodic basis and when certain events occur. A ratings downgrade could increase fees on PGE's revolving credit facilities and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Company's access to the commercial paper market, a principal source of short-term financing, or result in higher interest costs.

In addition, if Moody's Investors Service (Moody's) and/or S&P Global Ratings (S&P) reduce their rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Company's liquidity.

PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect the Company's results of operations, financial condition, or cash flows.

From time to time in the normal course of its business, PGE is subject to various regulatory proceedings, lawsuits, claims, and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could require that the Company incur expenditures over an extended period of time and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position, or results of operations.

There are certain pending legal and regulatory proceedings, such as the remediation efforts related to the Portland Harbor site and the Carty related litigation and cost recovery, which may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.—"Legal Proceedings" and Note 17, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Reduced river flows and unfavorable wind conditions can adversely affect generation from hydroelectric and wind generating resources. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations.

PGE derives a significant portion of its power supply from its own hydroelectric facilities and through long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snow pack levels affect river flows and the resulting amount of energy generated by these facilities. Shortfalls in energy expected from lower cost hydroelectric generating resources would require increased energy from the Company's other generating resources and/or power purchases in the wholesale market, which could have an adverse effect on results of operations.

PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Company's thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations.

Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power provided by hydroelectric and wind generating resources, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Company's results of operations, as well as a reduction in renewable energy credits and loss of production tax credits related to wind generating resources.

Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently envisioned.

Access to capital and credit markets is important to PGE's ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. In addition, contractual commitments and regulatory requirements may limit the Company's ability to delay or terminate certain projects. For additional information concerning PGE's capital requirements, see "*Capital Requirements*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Company's future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, restrictions on PGE's ability to access capital markets could affect its ability to execute its strategic plan.

Legislative or regulatory efforts to reduce GHG emissions could lead to increased capital and operating costs and have an adverse impact on the Company's results of operations.

Future legislation or regulations could result in limitations on GHG emissions from the Company's fossil fuel-fired generation facilities. Compliance with any GHG emissions reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the replacement of high-emitting generation facilities with lower-emitting facilities.

The cost to comply with potential GHG emissions reduction requirements is subject to significant uncertainties, including those related to: i) the timing of the implementation of emissions reduction rules; ii) required levels of emissions reductions; iii) requirements with respect to the allocation of emissions allowances; iv) the maturation, regulation, and commercialization of carbon capture and sequestration technology; and v) PGE's compliance alternatives. Although the Company cannot currently estimate the effect of future legislation or regulations on its results of operations, financial condition, or cash flows, the costs of compliance with such legislation or regulations could be material.

Under certain circumstances, banks participating in PGE's credit facilities could decline to fund advances requested by the Company or could withdraw from participation in the credit facilities.

PGE currently has a syndicated unsecured revolving credit facility with several banks for an aggregate amount of $500 million. The revolving credit facility provides a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings.

The revolving credit facility represents commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under the credit facility. However, in the event certain circumstances occur that could result in a material adverse change in the business, financial condition, or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facility.

In addition, it is possible that the Company might not be aware of certain developments at the time it makes such a representation in connection with a request for a loan, which could cause the representation to be untrue at the time made and constitute an event of default. Such a circumstance could result in a loss of the banks' commitments under the credit facilities and, in certain circumstances, the accelerated repayment of any outstanding loan balances.

A similar risk exists with respect to the Company's letter of credit facilities, which currently provide for a total capacity of $160 million.

Measures required to comply with state and federal regulations related to air emissions and water discharges from thermal generating plants could result in increased capital expenditures and operating costs and reduce generating capacity, which could adversely affect the Company's results of operations.

PGE is subject to state and federal requirements concerning air emissions and water discharges from thermal generating plants. For additional information, see the Environmental Matters section in Item 1.—"Business." These requirements could adversely affect the Company's results of operations by requiring: i) the installation of additional air emissions and water discharge controls at PGE's generating plants, which could result in increased capital expenditures; and ii) changes to the Company's operations that could increase operating costs and reduce generating capacity.

Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Company's liabilities related to such plans. Sustained declines in the fair value of the plans' assets could result in significant increases in funding requirements, which could adversely affect PGE's liquidity and results of operations.

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under PGE's defined benefit pension plan. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGE's funding requirements related to the pension plan. Additionally, changes in interest rates affect PGE's liabilities under the pension plan. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding.

Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Company's non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Company's operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans.

For additional information regarding PGE's contribution obligations under its pension and non-qualified benefit plans, see "*Contractual Obligations and Commercial Commitments*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations," and "*Pension and Other Postretirement Plans*" in Note 10, Employee Benefits, in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data."

Development of alternative technologies may negatively impact the value of PGE's generation facilities.

A basic premise of PGE's business is that generating electricity at central generation facilities achieves economies of scale and produces electricity at a relatively low price. Many companies and organizations conduct research and development activities to seek improvements in alternative technologies, such as fuel cells, photovoltaic (solar) cells, micro-turbines, and other forms of distributed generation. It is possible that advances in such technologies will reduce the cost of alternative methods of electricity production to a level that is equal to or below that of central thermal and wind generation facilities. Such a development could limit the Company's future growth opportunities and limit growth in demand for PGE's electric service.

Failure of PGE’s wholesale suppliers to perform their contractual obligations could adversely affect the Company’s ability to deliver electricity and increase the Company’s costs.

PGE relies on suppliers to deliver natural gas, coal, and electricity, in accordance with short- and long-term contracts. Failure of suppliers to comply with such contracts in a timely manner could disrupt the Company’s ability to deliver electricity and require PGE to incur additional expenses in order to meet the needs of its customers. In addition, as these contracts expire, the Company could be unable to continue to purchase natural gas, coal, or electricity on terms and conditions equivalent to those of existing agreements.

Operational changes required to comply with both existing and new environmental laws related to fish and wildlife could adversely affect PGE’s results of operations.

A portion of PGE’s total energy requirement is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. The listing of various plants and species of fish, birds, and other wildlife as threatened or endangered has resulted in significant operational changes to these projects. Salmon recovery plans could include further major operational changes to the region’s hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the availability of hydroelectric or wind generating resources to meet the Company’s energy requirements.

PGE could be vulnerable to cyber security attacks, data security breaches, acts of terrorism, or other similar events that could disrupt its operations, require significant expenditures, or result in claims against the Company.

In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. Despite the security measures in place, the Company’s systems, and those of third-party service providers, could be vulnerable to cyber security attacks, data security breaches, acts of terrorism, or other similar events that could disrupt operations or result in the release of sensitive or confidential information. Such events could cause a shutdown of service or expose PGE to liability. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance may not be adequate to protect the Company against liability in all cases. In addition, PGE is subject to the risk that insurers will dispute or be unable to perform their obligations to the Company.

Storms and other natural disasters could damage the Company’s facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction.

PGE has exposure to natural disasters that can cause significant damage to its generation, transmission, and distribution facilities. Such events can interrupt the delivery of electricity, increase repair and service restoration expenses, and reduce revenues. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. As a regulated utility, the Company is required to provide service to all customers within its service territory and generally has been afforded liability protection against customer claims related to service failures beyond the Company’s reasonable control.

Beginning in 2011, the OPUC authorized the Company to collect $2 million annually from retail customers for such damages and to defer any amount not utilized in the current year. During 2015 and 2016, PGE fully utilized the existing reserve balance as a result of restoration costs associated with storm damage occurring during those years.

PGE utilizes insurance, when possible, to mitigate the cost of physical loss or damage to the Company's property. As cost effective insurance coverage for transmission and distribution line property (poles and wires) is currently not available, however, the Company would likely seek recovery of large losses to such property through the ratemaking process.

PGE is subject to extensive regulation that affects the Company's operations and costs.

PGE is subject to regulation by the FERC, the OPUC, and by certain federal, state, and local authorities under environmental and other laws. Such regulation significantly influences the Company's operating environment and can have an effect on many aspects of its business. Changes to regulations are ongoing, and the Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business. However, changes in regulations could delay or adversely affect business planning and transactions, and substantially increase the Company's costs.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

PGE's principal property, plant, and equipment are generally located on land owned by the Company or land under the control of the Company pursuant to existing leases, federal or state licenses, easements, or other agreements. In some cases, meters and transformers are located on customer property. PGE leases its corporate headquarters complex, located in Portland, Oregon. The Indenture securing the Company's First Mortgage Bonds (FMBs) constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2016:

Facility	Location	Net Capacity [1]	
Wholly-owned:			
Natural Gas/Oil:			
Beaver	Clatskanie, Oregon	508	MW
Carty	Boardman, Oregon	434	
Port Westward Unit 1 (PW1)	Clatskanie, Oregon	395	
Coyote Springs	Boardman, Oregon	243	
Port Westward Unit 2 (PW2)	Clatskanie, Oregon	225	
Wind:			
Biglow Canyon	Sherman County, Oregon	450	
Tucannon River	Columbia County, Washington	267	
Hydro:			
North Fork	Clackamas River	58	
Faraday	Clackamas River	46	
Oak Grove	Clackamas River	45	
River Mill	Clackamas River	25	
T.W. Sullivan	Willamette River	18	
Jointly-owned [2]:			
Coal:			
Boardman [3]	Boardman, Oregon	518	
Colstrip [4]	Colstrip, Montana	296	
Hydro:			
Round Butte [5]	Deschutes River	230	
Pelton [5]	Deschutes River	73	
Net capacity		3,831	MW

(1) Represents net capacity of generating unit as demonstrated by actual operating or test experience, net of electricity used in the operation of a given facility. For wind-powered generating facilities, nameplate ratings are used in place of net capacity. A generator's nameplate rating is its full-load capacity under normal operating conditions as defined by the manufacturer.
(2) Reflects PGE's ownership share.
(3) PGE operates Boardman and has a 90% ownership interest.
(4) Talen Montana, LLC operates Colstrip and PGE has a 20% ownership interest.
(5) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the FPA. The licenses for the hydroelectric projects on the three different rivers expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055.

Transmission and Distribution

PGE owns and/or has contractual rights associated with transmission lines that deliver electricity from its generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2016, PGE owned an electric transmission system consisting of 1,248 circuit miles as follows: 287 circuit miles of 500 kV line; 402 circuit miles of 230 kV line; and 559 miles of 115 kV line. The Company also has 27,259 circuit miles of distribution lines that deliver electricity to its customers.

The Company also has an ownership interest in the following:

- Approximately 15% of the capacity on the Colstrip Project Transmission facilities from Colstrip to BPA's transmission system; and
- Approximately 20% of the capacity on the Pacific Northwest Intertie, a 4,800 MW transmission facility between John Day, in northern Oregon, and Malin, in southern Oregon near the California border. The Pacific Northwest Intertie is used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

In addition, the Company has contractual rights to the following transmission capacity:

- Approximately 3,490 MW of firm BPA transmission on BPA's system to PGE's service territory in Oregon; and
- 150 MW of firm BPA transmission from the Mid-Columbia projects in Washington to the northern end of the Pacific Northwest AC Intertie, near John Day, Oregon, 5 MW to Tucannon River, and 5 MW to Biglow Canyon.

ITEM 3. LEGAL PROCEEDINGS.

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court; and Morgan v. Portland General Electric Company, Marion County Circuit Court.

In January 2003, two class action suits were filed in Marion County Circuit Court (Circuit Court) against PGE. The Dreyer case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2000 (Current Class) and the Morgan case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2000, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of $190 million plus interest for the Current Class and $70 million plus interest for the Former Class, from the inclusion of a return on investment of Trojan in the rates PGE charged its customers.

In April 2004, the Class Action Plaintiffs filed a Motion for Partial Summary Judgment and in July 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs' claims. In December 2004, the Judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. In March 2005, PGE filed two Petitions with the Oregon Supreme Court asking the Supreme Court to take jurisdiction and command the trial Judge to dismiss the complaints, or to show cause why they should not be dismissed, and seeking to overturn the Class Certification.

In August 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions abating these class action proceedings until the OPUC responded with respect to the certain issues that had been remanded to the OPUC by the Circuit Court. In October 2006, the Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions.

Following the October 2014 decision of the Oregon Supreme Court upholding the OPUC refund order in the related Trojan regulatory proceeding, the Circuit Court granted PGE's motion to lift the abatement in June 2015. PGE filed a motion for summary judgment dismissing the lawsuits. Following oral argument on PGE's motion for summary judgment, Plaintiffs moved to amend the complaints. PGE opposed the request to amend.

On February 22, 2016, the Circuit Court denied the plaintiff's motion to amend the Complaint and, on March 16, 2016, entered a general judgment that granted the Company's motion for summary judgment and dismissed all claims by the plaintiffs.

On April 14, 2016, the plaintiffs appealed the general judgment of the Circuit Court in the Court of Appeals for the State of Oregon. For additional information on this matter, see Note 17, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—“Financial Statements and Supplementary Data.”

Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western System Power Pool Agreement, Federal Energy Regulatory Commission and Ninth Circuit Court of Appeals (collectively, Pacific Northwest Refund proceeding).

In 2001, the FERC called for a hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001 (Pacific Northwest Refund proceeding). During that period, PGE both sold and purchased electricity in the Pacific Northwest. Although FERC’s original decision terminated the proceeding and denied the claims for refunds, upon appeal of this decision to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit), the Ninth Circuit remanded the case to the FERC to, among other things, address market manipulation evidence and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings.

In response to the Ninth Circuit remand, the FERC issued several procedural orders that established an evidentiary hearing, defined the scope of the hearing, expanded the refund period to include January 1, 2000 through December 24, 2000 for certain types of claims, and described the burden of proof that must be met to justify abrogation of the contracts at issue and the imposition of refunds. Those orders included a finding by the FERC that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome either by: i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract; or ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest. The FERC also held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Refund proponents appealed these procedural orders at the Ninth Circuit. On December 17, 2015, the Ninth Circuit held that the FERC reasonably applied the *Mobile-Sierra* presumption to the class of contracts at issue in the proceedings and dismissed evidentiary challenges related to the scope of the proceeding.

Plaintiffs on behalf of the California Energy Resources Scheduling division of the California Department of Water Resources filed a request for rehearing on February 1, 2016. By order issued April 18, 2016, the Ninth Circuit denied plaintiffs’ request for panel rehearing of its decision regarding application of the *Mobile-Sierra* presumption.

In response to the evidence and arguments presented during the hearing, in May 2015, the FERC issued an order finding that the refund proponents had failed to meet the *Mobile-Sierra* burden with respect to all but one respondent. In December 2015, the FERC denied all requests for rehearing of its order. With respect to the remaining respondent, FERC ordered additional proceedings, and, in an order issued October 18, 2016, rejected the Plaintiffs’ request for refunds from the respondent, finding that the Plaintiffs had not met their Mobile-Sierra burden of proof.

The Company has settled all of the direct claims asserted against it in the proceedings for an immaterial amount. The settlements and associated FERC orders did not fully eliminate the potential for so-called “ripple claims,” which have been described by the FERC as “sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund.” As a result of the FERC orders to date, there are only two sellers from whom ripple claims could arise if those orders are overturned on appeal. Both of these sellers have now authorized on-the-record representations that they would not pursue ripple claims if they were required to pay refunds. As a result, the Company does not believe that it will incur any material loss in connection with this matter.

Portland General Electric Company v. Liberty Mutual Insurance Company and Zurich American Insurance Company, U.S. District Court of the District of Oregon.

In 2013, the Company entered into an agreement (Construction Agreement) with its engineering, procurement and construction contractor - Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership, an affiliate of Abengoa S.A. (collectively, the “Contractor”) - for the construction of Carty. Liberty Mutual Insurance Company and Zurich American Insurance Company (hereinafter referred to collectively as the “Sureties”) provided a performance bond of $145.6 million (Performance Bond) under the Construction Agreement.

On December 18, 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. On January 28, 2016, the Company received notice from the International Chamber of Commerce International Court of Arbitration that Abengoa S.A. had submitted a request for arbitration. In the request, Abengoa S.A. alleged that the Company’s termination of the Construction Agreement was wrongful and in breach of the agreement terms and does not give rise to any liability of Abengoa S.A. under the terms of a guaranty in favor of PGE and pursuant to which Abengoa S.A. agreed to guaranty certain obligations of the Contractor under the Construction Agreement. Abengoa S.A. is also seeking to implead the Contractor into this arbitration. PGE disagrees with the assertions in the request for arbitration and, on February 29, 2016, filed a complaint and motion for preliminary injunction in the U.S. District Court for the District of Oregon seeking to have the arbitration claim dismissed on the grounds that the Company has not made a demand under the Abengoa S.A. guaranty, and therefore the matter is not ripe for arbitration.

On March 28, 2016, Abengoa S.A. and several of its foreign affiliates filed petitions for recognition under Chapter 15 of the U.S. Bankruptcy Code requesting interim relief, including an injunction precluding the prosecution of any proceedings against the Chapter 15 debtors. On March 29, 2016, a number of Abengoa S.A.’s U.S. subsidiaries, including the four entities that collectively comprise the Contractor, filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. As a result, on April 5, 2016, the U.S. District Court issued an order stating that the Company’s District Court action against Abengoa S.A. was stayed. In June 2016, the Company filed with the bankruptcy court in the Chapter 11 proceeding a motion for relief from stay with respect to the four entities that collectively comprise the Contractor, which allows the Company to bring claims against such entities in the U.S. District Court. On October 21, 2016, PGE filed a complaint in the U.S. District Court for the District of Oregon against Abeinsa for failure to satisfy its obligations under the Construction Agreement. For further information regarding this complaint, see “Portland General Electric Company v. Abeinsa EPC LLC, Abener Construction Services, LLC (formerly known as Abener Engineering and Construction Services, LLC), Teyma Construction USA LLC, and Abeinsa Abener Teyma General Partnership, U.S. District Court of the District of Oregon,” below.

On March 9, 2016, the Sureties delivered a letter to the Company denying liability in whole under the Performance Bond. In the letter, the Sureties make the following assertions in support of their determination:

1. that, because Abengoa S.A. has alleged that PGE wrongfully terminated the Construction Agreement, PGE must disprove such claim as a condition precedent to recovery under the Performance Bond; and
2. that, irrespective of the outcome of the foregoing wrongful termination claim, the Sureties have various contractual and equitable defenses to payment and are not liable to PGE for any amount under the Performance Bond.

The Company disagrees with the foregoing assertions and on March 23, 2016 filed a breach of contract action against the Sureties in the U.S. District Court for the District of Oregon. The Company’s complaint disputes the Sureties’ assertion that the Company wrongfully terminated the Construction Agreement and asserts that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Sureties’ breach of contract, including damages in excess of the $145.6 million stated amount of the Performance Bond. Such damages include additional costs incurred by PGE to complete Carty.

On April 15, 2016, the Sureties filed a motion to stay this U.S. District Court proceeding, alleging that PGE's claims should be addressed in the arbitration proceeding initiated by Abengoa S.A., and referenced above, because PGE's claims are intertwined with the issues involved in such arbitration and all parties necessary to resolve PGE's claims are parties to the arbitration. PGE opposed the motion and filed a motion to enjoin the Sureties from pursuing, in the ICC arbitration proceeding, claims relating to the Performance Bond.

On July 27, 2016, the judge denied the Sureties' motion to stay the case in favor of a pending ICC Arbitration and granted PGE's motion for an injunction prohibiting the Sureties from pursuing any Performance Bond claims in the ICC Arbitration. The Sureties appealed the rulings to the Ninth Circuit Court of Appeals. On December 13, 2016, the Ninth Circuit issued an Order staying the district court proceeding pending a decision on the Sureties' appeal. Oral argument on the Sureties' appeal is scheduled for May 2017.

For additional information on this matter, see Note 17, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Portland General Electric Company v. Abeinsa EPC LLC, Abener Construction Services, LLC (formerly known as Abener Engineering and Construction Services, LLC), Teyma Construction USA LLC, and Abeinsa Abener Teyma General Partnership, U.S. District Court of the District of Oregon.

On October 21, 2016, PGE filed a complaint in the U.S. District Court of the District of Oregon against Abeinsa for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from Abeinsa in excess of $200 million for: i) costs incurred to complete construction of Carty, settle claims with unpaid contractors and vendors, and remove liens; and ii) damages in excess of the construction costs, including a project management fee, liquidated damages under the Construction Agreement, legal fees and costs, damages due to delay of the project, warranty costs, and interest. For additional information on this matter, see Note 17, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

PGE's common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol "POR". As of February 3, 2017, there were 800 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $43.55 per share. The following table sets forth, for the periods indicated, the highest and lowest sales prices of PGE's common stock as reported on the NYSE.

	High	Low	Dividends Declared Per Share
2016			
Fourth Quarter	$ 44.32	$ 40.28	$ 0.32
Third Quarter	45.21	41.51	0.32
Second Quarter	44.12	37.77	0.32
First Quarter	40.48	35.27	0.30
2015			
Fourth Quarter	$ 39.08	$ 34.97	$ 0.30
Third Quarter	38.00	33.09	0.30
Second Quarter	37.69	33.04	0.30
First Quarter	41.04	34.72	0.28

While PGE expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration will depend upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

ITEM 6. SELECTED FINANCIAL DATA.

The following consolidated selected financial data should be read in conjunction with Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8.—"Financial Statements and Supplementary Data."

	Years Ended December 31,				
	2016	2015	2014	2013	2012
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues, net	$ 1,923	$ 1,898	$ 1,900	$ 1,810	$ 1,805
Gross margin	68%	65%	62%	58%	60%
Income from operations*	$ 333	$ 309	$ 293	$ 206	$ 302
Net income*	193	172	174	104	140
Net income attributable to Portland General Electric Company*	193	172	175	105	141
Earnings per share—basic*	2.17	2.05	2.24	1.36	1.87
Earnings per share—diluted*	2.16	2.04	2.18	1.35	1.87
Dividends declared per common share	1.260	1.180	1.115	1.095	1.075
Statement of Cash Flows Data:					
Capital expenditures	584	598	1,007	656	303

* The year ended December 31, 2013 includes $52 million of costs expensed related to the Company's Cascade Crossing Transmission Project, which was originally proposed as a 215-mile, 500 kV transmission project.

	As of December 31,				
	2016	2015	2014	2013	2012
	(Dollars in millions)				
Balance Sheet Data:					
Total assets*	$ 7,527	$ 7,210	$ 7,030	$ 6,090	$ 5,661
Total long-term debt*	2,350	2,193	2,489	1,905	1,627
Total capital lease obligations	54	—	—	—	—
Total Portland General Electric Company shareholders’ equity	2,344	2,258	1,911	1,819	1,728
Common equity ratio*	49.4%	50.7%	43.4%	48.9%	51.3%

* Total assets, total long-term debt, and common equity ratios have been adjusted to reflect the retrospective adoption of ASU 2015-03, *Interest-Imputation of Interest (Subtopic 835-30)* for the years ended December 31, 2015 through December 31, 2012. For more information, see “*Recently Adopted Accounting Pronouncements*” in Note 2, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements in Item 8.—“Financial Statements and Supplementary Data.”

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Forward-Looking Statements

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements include, but are not limited to, statements that relate to expectations, beliefs, plans, assumptions and objectives concerning future results of operations, business prospects, future loads, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events or performance and other matters. Words or phrases such as “anticipates,” “believes,” “estimates,” “expects,” “intends,” “plans,” “predicts,” “projects,” “will likely result,” “will continue,” “should,” or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis including, but not limited to, management’s examination of historical operating trends and data contained either in internal records or available from third parties, but there can be no assurance that PGE’s expectations, beliefs, or projections will be achieved or accomplished.

In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes for PGE to differ materially from those discussed in forward-looking statements include:

- governmental policies and regulatory audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;

- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 17, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K;
- unseasonable or extreme weather and other natural phenomena, which could affect customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;
- operational factors affecting PGE's power generating facilities, including forced outages, hydro and wind conditions, and disruption of fuel supply, any of which may cause the Company to incur repair costs or purchase replacement power at increased costs;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, either of which could result in the Company's inability to recover project costs;
- volatility in wholesale power and natural gas prices, which could require PGE to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to power and natural gas purchase agreements;
- changes in the availability and price of wholesale power and fuels, including natural gas, coal, and oil, and the impact of such changes on the Company's power costs;
- capital market conditions, including availability of capital, volatility of interest rates, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, any of which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, and the repayments of maturing debt;
- future laws, regulations, and proceedings that could increase the Company's costs of operating its thermal generating plants, or affect the operations of such plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- changes in, and compliance with, environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures;
- declines in the fair value of securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities or information technology systems, or result in the release of confidential customer, employee, or Company information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and a significant number of employees approaching retirement;
- new federal, state, and local laws that could have adverse effects on operating results;
- political and economic conditions;
- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors or assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Overview

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide an understanding of the business environment, results of operations, and financial condition of PGE. MD&A should be read in conjunction with the Company's consolidated financial statements contained in this report, and other periodic and current reports filed with the SEC.

PGE filed its 2016 IRP with the OPUC in mid- November 2016. The areas of focus for the 2016 IRP include, among other topics, acquisition of additional resources that may be needed in order to meet RPS requirements and to replace energy and capacity from Boardman, which is scheduled to cease coal-fired operations at the end of 2020. For further information on the Company's 2016 IRP, see *"Integrated Resource Plan"* in the Regulation section of Item 1.—"Business."

During 2016, PGE committed to join the western EIM with a target participation date in the fall of 2017. The EIM is a real-time energy wholesale market that automatically dispatches the lowest-cost electricity resources, while optimizing use of renewable energy over a large geographic area. For further information on the Company's participation in the EIM, see *"Future Energy Resource Strategy"* in the Power Supply section of Item 1.—"Business."

The State of Oregon passed Senate Bill 1547, effective March 8, 2016, a law referred to as the Oregon Clean Electricity and Coal Transition Plan (OCEP). The legislation prevents large utilities from including the costs and benefits associated with coal-fired generation in their Oregon retail rates after 2030, with certain exceptions, and increases the RPS percentages in future years. For further information on the OCEP, see "Legal, Regulatory and Environmental" in this Overview section of Item 7.

The discussion that follows in this MD&A more fully describes these and other operating activities and provides additional information related to the Company's legal, regulatory, and environmental matters, results of operations, and liquidity and financing.

Carty—On July 29, 2016, Carty, a natural gas-fired baseload resource in Eastern Oregon, was placed into service. As of December 31, 2016, PGE had $634 million in Electric utility plant in service related to Carty. The Company currently estimates that the total capital expenditures for Carty will be approximately $640 million. This cost estimate does not reflect any amounts that may be received from the Sureties pursuant to the Performance Bond or from the Contractor or Abengoa S.A. This estimate also excludes approximately $17 million of lien claims filed against PGE for goods and services provided under contracts with the former Contractor. The Company believes these liens are invalid and is contesting the claims in the courts. For additional details regarding various legal proceedings related to Carty, see Note 17, Contingencies, in the Notes to the Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data."

The final order issued by the OPUC on November 3, 2015 in connection with the Company's 2016 General Rate Case authorized the inclusion in customer prices of capital costs for Carty of up to $514 million, as well as Carty's operating costs, at such time that the plant was placed into service, provided that occurred by July 31, 2016. As Carty was placed in service on July 29, 2016, the Company was authorized to include in customer prices, effective August 1, 2016, its revenue requirement necessary to allow for recovery of capital costs of up to $514 million associated with the construction of Carty, as well as operating costs. The price change consisted of an $85 million annualized increase related to cost recovery of Carty and a $41 million annualized decrease ($17 million over the remainder of 2016) related to the amortization of certain customer credits through supplemental tariffs. As actual project costs for Carty have exceeded $514 million, the Company has incurred a higher cost of service than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation and interest expense.

On July 29, 2016, the Company also requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the incremental capital costs for Carty, starting from its in service date, to the date that such amounts are approved in a subsequent GRC proceeding. The Company has requested the OPUC delay its review of this deferral request until the Company's claims against the Sureties have been resolved. Until such time, the effects of this higher cost of service will be recognized in the Company's results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP. Incremental expenses related to Carty, primarily due to depreciation and amortization, were $3 million for the year ended December 31, 2016 and are estimated to be $6 million in 2017. Any amounts approved by the OPUC for recovery under the deferral filing would be recognized in earnings in the period of such approval.

Capital Requirements and Financing—PGE's capital requirements amounted to $596 million for 2016, with $190 million related to the construction of Carty, excluding AFDC. The remainder of the 2016 capital requirements related to ongoing capital expenditures for the upgrade, replacement, and expansion of transmission, distribution, and generation infrastructure, as well as technology enhancements and expenditures related to hydro licensing and construction. During 2016, the combination of cash from operations in the amount of $553 million and proceeds from issuances of FMBs and unsecured term loans in the amount of $290 million funded the Company's capital requirements.

Capital requirements in 2017 are expected to approximate $610 million. PGE plans to fund the 2017 capital requirements and current maturities of long-term debt of $150 million with cash from operations during 2017, which is expected to range from $450 million to $500 million and the issuance of debt securities of approximately $450 million. These amounts do not include any estimated proceeds to be received from the Sureties pursuant to the performance bond, which cannot be reasonably estimated at this time. For further information, see the "*Liquidity*" and the "*Debt and Equity Financings*" sections of this Item 7.

General Rate Cases—PGE plans to file a 2018 GRC with the OPUC by the end of February 2017 that will be based on a 2018 test year and include investments to ensure system safety and reliability and better meet customers' changing needs and service expectations. Regulatory review of the 2018 GRC is expected to occur throughout 2017, with new customer prices effective in January 2018.

In February 2015, PGE filed with the OPUC a 2016 GRC, which was based on a 2016 test year and included costs related to Carty. In November 2015, the OPUC issued an order in the Company's 2016 GRC, intended primarily to allow recovery of costs associated with the construction and operation of Carty. The annual revenue requirement change was implemented in two phases, with the first, a decrease, effective January 1, 2016 consisting of a reduction in base business costs and a decrease related to the amortization and recognition of certain customer credits through supplemental tariffs. The second phase was a price increase, consisting of the combination of an increase related to the cost recovery of Carty and a decrease related to the amortization of certain customer credits through supplemental tariffs, effective when Carty was placed into service. For further discussion on Carty, see *"Carty"* in this Overview section of Item 7.

The 2016 GRC filing, as well as copies of the orders, direct testimony, exhibits, and stipulations are available on the OPUC website at www.oregon.gov/puc.

Operating Activities—PGE is a vertically integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity, as well as the wholesale purchase and sale of electricity and natural gas in the United States and Canada to meet its retail load requirements. The Company generates revenues and cash flows primarily from the retail sale and distribution of electricity to customers in its service territory in the State of Oregon.

The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues and income from operations to fluctuate from period to period. Historically, PGE has been a winter-peaking utility that typically experiences its highest retail energy demand during the winter heating season, although increased use of air conditioning in the Company's service territory has caused the summer peaks to increase in recent years and the long-term load forecasts show summer peaks exceeding winter peaks. Retail customer price changes and usage patterns, which can be affected by the economy, also have an effect on revenues while wholesale power availability and price, hydro and wind generation, and fuel costs for thermal plants can also affect income from operations.

Customers and Demand—In 2016, retail energy deliveries decreased 2.1% from 2015, which was driven by decreases in industrial and commercial energy deliveries, partially offset by an increase in residential energy deliveries. For 2016 and 2015, the average number of retail customers and deliveries, by customer type, were as follows:

	2016		2015		
	Average Number of Customers	**Energy Deliveries ***	**Average Number of Customers**	**Energy Deliveries ***	**Increase/ (Decrease) in Energy Deliveries**
Residential	752,365	7,348	742,467	7,325	0.3 %
Commercial (PGE sales only)	106,460	6,932	105,472	7,002	(1.0)%
Direct Access	313	525	330	509	3.1 %
Total Commercial	106,773	7,457	105,802	7,511	(0.7)%
Industrial (PGE sales only)	195	2,968	199	3,369	(11.9)%
Direct Access	63	1,198	61	1,177	1.8 %
Total Industrial	258	4,166	255	4,546	(8.4)%
Total (PGE sales only)	859,020	17,248	848,138	17,696	(2.5)%
Total Direct Access	376	1,723	391	1,686	2.2 %
Total	859,396	18,971	848,524	19,382	(2.1)%

* In thousands of MWh.

In late 2015, a large paper manufacturing customer, to which PGE has delivered approximately 450 thousand MWhs annually, with corresponding revenues of approximately $20 million, ceased operations. Although the majority of power this customer purchased was under the Company’s daily market index-based price option, a portion was at cost of service prices. The Company’s 2016 GRC took into consideration the loss of this customer load and incorporated it into prices and load forecasts for 2016 and, as a result, minimal earnings impact occurred. After adjusting for the loss of this large customer, industrial energy deliveries increased by 1.4% and total energy deliveries increased by 0.1% in 2016. The increase in industrial energy deliveries developed as increased energy deliveries to the high tech manufacturing sector were partially offset by decreased energy deliveries to the metals and transportation equipment manufacturing sectors.

The increase in demand from residential customers is largely attributable to strong customer growth of 1.3% for 2016 relative to 2015. The increase is largely offset by a decrease of 1.0% in residential use per customer which is driven, primarily, by unfavorable year over year weather conditions. Both 2015 and 2016 experienced unusually warm temperatures during the winter heating season, reducing residential energy deliveries, however 2016 did not experience the offsetting warm temperatures during the cooling season that were experienced in 2015.

The full year 2015 was the warmest year on record for the State of Oregon. During the summer months, the generally warmer weather increased residential energy deliveries slightly due to cooling demand, but only partially offset the decline in energy deliveries that resulted during the heating season. Total heating degree-days in 2016 (an indication of the extent to which customers are likely to use, or have used, electricity for heating) were 16% lower than the 15-year average, although 3% above total heating degree-days in 2015. For further detail on heating and cooling degree-days, see *“Revenues”* in the 2016 Compared to 2015 section of Results of Operations in this Item 7. Lower commercial deliveries, despite a 0.9% growth in the average number of customers, reflects unfavorable weather conditions, and slightly lower demand from a few groups, including food stores, which were impacted by a series of mergers and bankruptcies, government and education, and irrigation customers in 2016 due to the extremely dry conditions that existed in 2015. On a weather adjusted basis, commercial deliveries for 2016 were comparable to 2015. Energy efficiency continues to impact growth, and conservation and building codes and standards are likely reducing energy deliveries beyond the impact of energy efficiency programs.

Energy efficiency and conservation efforts by retail customers influence demand, although the financial effects of such efforts by residential and certain commercial customers are mitigated with the decoupling mechanism, which is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts. The mechanism provides for collection from (or refund to) customers if weather adjusted use per customer is less (or more) than the projected baseline set in the Company's most recent approved general rate case.

For 2016, PGE recorded an estimated collection of $3 million as weather adjusted energy use per customer was less than that estimated and approved in the Company's 2016 GRC. A final determination of the 2016 estimate will be made by the OPUC through a public filing and review in 2017. Any resulting collection from customers is expected to begin January 1, 2018. The $9 million estimated refund for the 2015 year was submitted to the OPUC for review during 2016. The resulting refund to customers began January 1, 2017. For 2014, amortization of the net $5 million refund amount began in January 2016 following a final determination of the amount through a public filing and review by the OPUC during 2015.

Power Operations—PGE utilizes a combination of its own generating resources and wholesale market transactions to meet the energy needs of its retail customers. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, the Company continuously makes economic dispatch decisions in an effort to obtain reasonably-priced power for its retail customers. As a result, the amount of power generated and purchased in the wholesale market to meet the Company's retail load requirement can vary from period to period.

Plant availability is impacted by planned maintenance and forced, or unplanned, outages, during which the respective plant is unavailable to provide power. PGE's thermal generating plants require varying levels of annual maintenance, which is generally performed during the second quarter of the year. Availability of the plants PGE operates approximated 93%, 93%, and 92% for the years ended December 31, 2016, 2015, and 2014, respectively, with the availability of Colstrip, which PGE does not operate, approximating 85%, 93%, and 83%, respectively.

During the year ended December 31, 2016, the Company's generating plants provided approximately 70% of its retail load requirement compared to 65% in 2015 and 58% in 2014. Through the addition of Carty in July 2016, and Tucannon River and PW2 in late 2014, PGE has the ability to economically generate a greater portion of its total system load and reduce reliance on higher-cost purchased power.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects increased 5% in 2016 compared to 2015, primarily due to more favorable hydro conditions in 2016. These resources provided 17% of the Company's retail load requirement for 2016, compared with 16% for 2015 and 18% for 2014. Energy received from these sources did not materially differ from the projections (or "normal") included in the Company's AUT in 2016, fell short of projections by 7% in 2015, and exceeded projections by 2% in 2014. Such projections, which are finalized with the OPUC in November each year, establish the power cost component of retail prices for the following calendar year. "Normal" represents the level of energy forecasted to be received from hydroelectric resources for the year and is based on average regional hydro conditions over a recent 30 year period. Any shortfall is generally replaced with power from higher cost sources, while any excess in hydro generation from that projected in the AUT generally displaces power from higher cost sources. See *"Purchased power and fuel"* in the 2016 Compared to 2015 section of Results of Operations in this Item 7. for further detail on regional hydro forecasts.

Energy expected to be received from wind generating resources (Biglow Canyon and Tucannon River) is projected annually in the AUT based on historical generation. Any excess in wind generation from that projected in the AUT generally displaces power from higher-cost sources, while any shortfall is generally replaced with power from higher-cost sources. Energy received from wind generating resources fell short of that projected in PGE's AUT by 7% in 2016, 15% in 2015 and 9% in 2014. As a result of the generation shortfalls, production tax credits have not materialized to the extent contemplated in the Company's prices.

Pursuant to the Company's PCAM, customer prices can be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in customer prices (baseline NVPC), as established under the AUT, and actual NVPC for the year, to the extent such difference is outside of a pre-determined "deadband," which ranges from $15 million below to $30 million above baseline NVPC. To the extent actual NVPC is above or below the deadband, the PCAM provides for 90% of the variance beyond the deadband to be collected from or refunded to customers, respectively, subject to a regulated earnings test. The following is a summary of the results of the PCAM as calculated for regulatory purposes for 2016, 2015, and 2014:

- For 2016, actual NVPC was below baseline NVPC by $10 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2016. A final determination regarding the 2016 PCAM results will be made by the OPUC through a public filing and review in 2017.
- For 2015, actual NVPC was below baseline NVPC by $3 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2015. A final determination regarding the 2015 PCAM results was made by the OPUC through a public filing and review in 2016, which confirmed no refund to customers pursuant to the PCAM for 2015.
- For 2014, actual NVPC was below baseline NVPC by $7 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2014. A final determination regarding the 2014 PCAM results was made by the OPUC through a public filing and review in 2015, which confirmed no refund to customers pursuant to the PCAM for 2014.

For further information concerning the PCAM, see *Power Costs* under "*OPUC and Other State of Oregon Regulation*" in the Regulation section of Item 1.—"Business."

Legal, Regulatory, and Environmental Matters—PGE is a party to certain proceedings, the ultimate outcome of which could have a material impact on the Company's results of operations and cash flows in future reporting periods. Such proceedings include, but are not limited to, matters related to:

- An investigation of environmental matters regarding Portland Harbor; and
- Claims pertaining to the termination of the Construction Agreement for Carty and recovery of incremental costs.

For additional information regarding the above and other matters, see Note 17, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Clean Power Plan—In August 2015, the EPA released a final rule, which it calls the "Clean Power Plan." Under the final rule, each state would have to reduce the carbon intensity of its power sector on a state-wide basis by an amount specified by the EPA. The rule established state-specific goals and is intended to result in a reduction of carbon emissions from existing power plants across all states to approximately 32% below 2005 levels by 2030. On February 9, 2016, the United States Supreme Court granted a stay, halting implementation and enforcement of the Clean Power Plan pending the resolution of legal challenges to the rule. For additional information regarding this new rule, see *"Air Quality"* in the Environmental Matters section of Item 1.—"Business."

Oregon Clean Electricity and Coal Transition Plan—The State of Oregon passed Senate Bill 1547, effective March 8, 2016, a law referred to as the OCEP. The legislation prevents large utilities from including the costs and benefits associated with coal-fired generation in their Oregon retail rates after 2030 (subject to an exception that extends this date until 2035 for PGE's output from the Colstrip facility), increases the RPS percentages in certain future years, changes the life of certain RECs, requires the development of community solar programs, seeks the development of transportation electrification programs, and requires that a portion of electricity come from small scale renewable or certain biomass projects.

Under the new law, PGE will be required to:

- fully depreciate its portion of the Colstrip facility by 2030, with the potential to utilize the output of the facility, in Oregon, until 2035;
- meet RPS thresholds of 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040;
- limit the life of RECs generated from facilities that become operational after 2022 to five years, but maintain the unlimited lifespan of all existing RECs and allow for the generation of additional unlimited RECs for a period of five years for projects on line before December 31, 2022;
- include projected PTCs in prices through any variable power cost forecasting process established by the OPUC, the first of which applied to the AUT filing for 2017; and
- include energy storage costs in its RAC filings.

The Company evaluated the potential impacts and incorporated the effects of the legislation into its 2016 IRP, which was filed with the OPUC in mid-November 2016.

In October 2016, the Company filed a tariff request with the OPUC seeking approval to incorporate in customer prices on January 1, 2017 the estimated annual $6 million effect of accelerating recovery of the Colstrip facility from 2042 to 2030, as required under the legislation. The OPUC approved the tariff request.

Ballot Measure 97—The State of Oregon had a citizens' initiative, Measure 97, on the November 2016 ballot that did not pass. If passed, it would have imposed a minimum tax of 2.5% on Oregon gross receipts on businesses with annual Oregon sales in excess of $25 million.

The following discussion highlights certain regulatory items, which have impacted, or are expected to impact, the Company's revenues, results of operations, or cash flows. In some cases, the Company deferred the related expenses or benefits as regulatory assets or liabilities, respectively, for later amortization and inclusion in customer prices, pending OPUC review and authorization.

Power Costs—Pursuant to the AUT process, PGE files annually an estimate of power costs for the following year. In the event a general rate case is filed in any given year, forecasted power costs would be included in such filing. Such forecast assumes the following for the different types of PGE-owned generating resources:

- Thermal—Expected operating conditions;
- Hydroelectric—Regional hydro generation based on historical stream flow data and current hydro operating parameters; and
- Wind—Generation levels based on a five-year historical rolling average of the wind farm. To the extent historical information is not available for a given year, the projections are based on wind generation studies.

As part of the Company's 2015 GRC, the OPUC approved the 2015 power cost forecast with an expected reduction in annual revenues of approximately $60 million. This amount was included in the overall $15 million revenue increase authorized by the OPUC in 2015 GRC with corresponding customer prices effective January 1, 2015. Actual NVPC for 2015, as calculated for regulatory purposes under the PCAM, was $3 million below the 2015 baseline NVPC.

In June 2016, the Company submitted the 2015 results of the PCAM to the OPUC for final regulatory review and determination of any customer refund or collection. Based on its review, no refund or collection resulted, and in September 2016, the OPUC issued an order to such effect. For further information, see *"Power Operations"* in the Operating Activities section of this Overview, above.

PGE's forecast of power costs for 2016 was approved by the OPUC with an expected reduction in annual revenues of approximately $31 million. This amount was included in the expected net annual revenue requirement increase the OPUC authorized under the Company's 2016 GRC. Actual NVPC for 2016, as calculated for regulatory purposes under the PCAM, was $10 million below the 2016 baseline NVPC. For further information, see *"General Rate Cases"* in this Overview section, above.

As a result of the OCEP legislation described above, PGE's 2017 AUT filing included projected PTCs for the 2017 calendar year. Prior to this legislative change, PGE included forecasts of PTCs only in General Rate Case proceedings. The inclusion of PTCs in the AUT provides for annual forecast updates for these estimated tax credits, thus reducing the risk of regulatory lag in terms of adjusting customer prices. The 2017 AUT filing, approved by the OPUC in November 2016 and included in customer prices effective January 1, 2017, projects a reduction in power costs for 2017, and a corresponding reduction in annual revenue requirement, of $56 million from 2016 levels.

Renewable Resource Costs—Pursuant to the RAC mechanism, PGE can recover in customer prices prudently incurred costs of renewable resources that are expected to be placed in service in the current year. The Company may submit a filing to the OPUC by April 1st each year, with prices expected to become effective January 1st of the following year. As part of the RAC, the OPUC has authorized the deferral of eligible costs not yet included in customer prices until the January 1st effective date.

On April 1, 2015, PGE submitted to the OPUC a RAC filing that requested revenue requirements related to a new 1.2 MW solar facility. Concurrent with this filing, PGE also requested authorization to engage in a property sale as part of a sale-leaseback agreement for the facility. The Company estimates that overall annual impact on annual revenues for this RAC filing will be an approximately $2 million reduction in revenues over a one-year period that began January 1, 2016. On October 2, 2015, the OPUC issued an order approving the deferral of costs associated with the facility.

On March 30, 2016, PGE submitted to the OPUC a RAC filing that requested no significant additions or deferrals for 2016.

Decoupling Mechanism—The decoupling mechanism, which the OPUC had authorized through 2016, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. On September 26, 2016, the OPUC issued an order extending the decoupling mechanism through 2019. The mechanism provides for collection from (or refund to) customers if weather adjusted use per customer is less (or more) than that projected in the Company's most recent general rate case.

The Company recorded an estimated collection of $3 million during the year ended December 31, 2016, which resulted from variances between actual weather adjusted use per customer and that projected in the 2016 GRC. Any collection is expected to occur over a one-year period, which would begin January 1, 2018. See *"Customers and Demand"* in the Operating Activities section of this Overview, above for further information on the decoupling mechanism.

Results of Operations

The following tables provide financial and operational information to be considered in conjunction with management's discussion and analysis of results of operations.

The consolidated statements of income are as follows for the years presented (dollars in millions):

	Years Ended December 31,					
	2016		2015		2014	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net	$ 1,923	100%	$ 1,898	100%	$ 1,900	100%
Purchased power and fuel	617	32	661	35	713	38
Gross margin	1,306	68	1,237	65	1,187	62
Other operating expenses:						
Generation, transmission and distribution	286	15	266	14	257	13
Administrative and other	247	13	241	13	227	12
Depreciation and amortization	321	16	305	16	301	16
Taxes other than income taxes	119	6	116	6	109	6
Total other operating expenses	973	50	928	49	894	47
Income from operations	333	18	309	16	293	15
Interest expense, net*	112	6	114	6	96	5
Other income:						
Allowance for equity funds used during construction	21	1	21	1	37	2
Miscellaneous income, net	1	—	1	—	1	—
Other income, net	22	1	22	1	38	2
Income before income taxes	243	13	217	11	235	12
Income tax expense	50	3	45	2	61	3
Net income	193	10	172	9	174	9
Less: net loss attributable to noncontrolling interests	—	—	—	—	(1)	—
Net income attributable to Portland General Electric Company	$ 193	10%	$ 172	9%	$ 175	9%

* Includes an allowance for borrowed funds used during construction of $11 million in 2016, $13 million in 2015, and $22 million in 2014.

Revenues, energy deliveries (presented in MWh), and average number of retail customers consist of the following for the years presented:

	Years Ended December 31,								
	2016			2015			2014		
Revenues[1] (dollars in millions):									
Retail:									
Residential	$	907	47%	$	895	47 %	$	893	47%
Commercial		665	35		662	35		657	34
Industrial		208	11		228	12		221	12
Subtotal		1,780	93		1,785	94		1,771	93
Other accrued (deferred) revenues, net		3	—		(10)	(1)		(8)	—
Total retail revenues		1,783	93		1,775	93		1,763	93
Wholesale revenues		103	5		88	5		95	5
Other operating revenues		37	2		35	2		42	2
Total revenues	$	1,923	100%	$	1,898	100 %	$	1,900	100%
Energy deliveries[2] (MWh in thousands):									
Retail:									
Residential		7,348	33%		7,325	33 %		7,462	34%
Commercial		7,457	33		7,511	34		7,494	34
Industrial		4,166	19		4,546	21		4,310	20
Total retail energy deliveries		18,971	85		19,382	88		19,266	88
Wholesale energy deliveries		3,352	15		2,560	12		2,520	12
Total energy deliveries		22,323	100%		21,942	100 %		21,786	100%
Average number of retail customers:									
Residential		752,365	88%		742,467	88 %		735,502	87%
Commercial		106,773	12		105,802	12		105,231	13
Industrial		258	—		255	—		260	—
Total		859,396	100%		848,524	100 %		840,993	100%

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those customers that purchase their energy from ESSs. Commercial revenues from ESS customers were $13 million, $12 million, and $15 million for 2016, 2015, and 2014, respectively. Industrial revenues from ESS customers were $15 million, $16 million, and $18 million for 2016, 2015, and 2014, respectively.

(2) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs. Commercial deliveries to ESS customers, in thousands of MWhs, were 525, 509, and 563 in 2016, 2015, and 2014, respectively. Industrial deliveries to ESS customers, in thousands of MWhs, were 1,198, 1,177, and 1,099 in 2016, 2015, and 2014, respectively.

PGE’s sources of energy, total system load, and retail load requirement for the years presented are as follows:

	Years Ended December 31,					
	2016		2015		2014	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Coal	3,492	16%	4,128	19%	4,466	21%
Natural gas	5,811	27	4,783	22	3,429	16
Total thermal	9,303	43	8,911	41	7,895	37
Hydro	1,629	8	1,453	7	1,750	8
Wind	1,912	9	1,788	8	1,172	6
Total generation	12,844	60	12,152	56	10,817	51
Purchased power:						
Term	6,961	32	7,364	35	8,552	40
Hydro	1,541	7	1,572	7	1,568	7
Wind	301	1	303	2	317	2
Total purchased power	8,803	40	9,239	44	10,437	49
Total system load	21,647	100%	21,391	100%	21,254	100%
Less: wholesale sales	(3,352)		(2,560)		(2,520)	
Retail load requirement	18,295		18,831		18,734	

Net income attributable to Portland General Electric Company for the year ended December 31, 2016 was $193 million, or $2.16 per diluted share, compared to $172 million, or $2.04 per diluted share, for the year ended December 31, 2015. The $21 million, or 12%, increase resulted in part from lower net variable power costs than what was reflected in revenues in the Company’s 2016 AUT. Purchased power and fuel costs decreased as the region experienced better hydro conditions in 2016 than in 2015, as well as improved wind generation, which also produced more PTCs. Average variable power cost per MWh declined 8% from 2015 and a 31% increase in the volume of wholesale energy sales also helped to reduce net variable power costs. Retail revenues increased only slightly as continued expansion in the average number of customers served and price changes authorized in the 2016 GRC were largely offset by the influences of weather and energy efficiency measures. Incremental depreciation expense related to the higher than planned construction cost of Carty, which were not covered in customer prices, as well as legal expenses related to litigation associated with the termination of the Carty Construction Agreement, along with higher storm and service restoration costs in 2016 somewhat countered the other improvements in net income.

Net income attributable to Portland General Electric Company for the year ended December 31, 2015 was $172 million, or $2.04 per diluted share, compared with $175 million, or $2.18 per diluted share, for the year ended December 31, 2014. The $3 million, or 2%, decrease in net income was largely a result of warmer than normal weather in the winter months of 2015 contributing to energy deliveries being lower than planned. The effects of the weather were partially offset by the increase in rate base associated with placing in service two generation resources in late 2014 that were included in customer price increases approved by the OPUC in the Company’s 2015 GRC. Purchased power and fuel costs declined year over year, although less than anticipated when customer prices were set for 2015, as the Company incurred higher than expected power costs due to below normal regional hydro and wind conditions. Other operating expenses increased largely as expected as a result of the operation of the two additional generation resources, although higher storm costs in 2015 and insurance recoveries in 2014 did contribute to the net income impact year over year. AFDC declined in 2015, which, in part, contributed to increased interest expense in 2015, as a result of the completion of the two new generating facilities. Lower income before income taxes and an increase in production tax credits from expanded wind generation served to reduce income tax expense in 2015, although not to the extent anticipated when customer prices were set in the 2015 GRC.

2016 Compared to 2015

Revenues increased $25 million, or 1.3%, in 2016 compared with 2015 as a result of the items discussed below.

Total retail revenues increased $8 million, or 0.5%, in 2016 compared with 2015, primarily due to the net effect of the following:

- A $49 million increase resulting from price changes, as authorized by the OPUC, including Carty going into service and into customer prices in mid-2016, as a result of the Company's 2016 GRC;
- A $10 million increase resulting from the Decoupling mechanism, as an estimated $3 million collection was recorded in 2016 compared to a refund in 2015;
- A $5 million increase due to a lower amount of customer credits related to tax credits in connection with operation of the ISFSI at the former Trojan nuclear power plant site. Such credits are directly offset in depreciation and amortization expense; and
- A $5 million overall increase due to various other largely offsetting tariff changes and adjustments; partially offset by
- A $38 million decrease in revenues related to a 2.1% decrease in retail energy deliveries, consisting of 8.4% and 0.7% decreases in industrial and commercial deliveries, respectively, partially offset by a 0.3% increase in residential deliveries. See *"Customers and Demand"* in the Overview section of this Item 7. for further information on customer demand; and
- A $23 million decrease related to the collection from customers during 2015 of costs associated with previous capital project deferrals, with no comparable collection in 2016. This decrease in revenues is largely offset by a comparable decrease in depreciation and amortization expense.

Total heating degree-days in 2016 were lower than the 15-year average (as provided by the National Weather Service, as measured at Portland International Airport) although somewhat greater than total heating degree-days in 2015. Total cooling degree-days in 2016 exceeded the 15-year average although were considerably less than the 2015 total. The following table presents the number of heating and cooling degree-days in 2016 and 2015, along with the 15-year averages:

	Heating Degree-Days			Cooling Degree-Days		
	2016	2015	15-Year Average	2016	2015	15-Year Average
1st quarter	1,585	1,481	1,866	—	—	—
2nd quarter	403	513	689	154	207	70
3rd quarter	78	76	78	394	573	399
4th quarter	1,486	1,391	1,600	—	5	2
Total	3,552	3,461	4,233	548	785	471
Increase (decrease) from the 15-year average	(16)%	(18)%		16%	67%	

On a weather adjusted basis, retail energy deliveries in 2016 were 1.4% below 2015, although one large paper customer ceased operations in late 2015. On a comparable year over year basis, with the removal of the one large paper customer load from the 2015 year, the Company experienced weather adjusted load growth of 0.9%. PGE projects that retail energy deliveries for 2017 will be nearly comparable to or slightly lower than 2016 weather adjusted levels, after allowance for energy efficiency and conservation efforts.

Wholesale revenues result from sales of electricity to utilities and power marketers made in the Company's efforts to secure reasonably priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. Such sales can vary significantly from year to year as a result of economic conditions, power and fuel prices, hydro and wind availability, and customer demand.

In 2016, the $15 million, or 17%, increase in wholesale revenues from 2015 consisted of a $27 million increase related to 31% greater wholesale sales volume partially offset by a $12 million decrease related to 11% lower average wholesale market prices.

Other operating revenues increased $2 million, or 6%, in 2016 from 2015, primarily due to a $2 million increase in resale of unneeded natural gas in combination with several smaller, rather offsetting items including revenues from broadband fiber deployment and steam sales.

Purchased power and fuel expense includes the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts. In 2016, Purchased power and fuel expense decreased $44 million, or 7%, from 2015, which was driven by a $51 million, or 8%, decline related to the decrease in the average variable power cost per MWh to $28.50 in 2016 from $30.91 in 2015, partially offset by a $7 million increase resulting from a 1% increase in total system load.

The decrease related to average variable power cost per MWh was driven primarily by a reduction in purchased power prices. The net increase in total system load was comprised of a $38 million, or 22%, increase due to energy generated from the Company's natural gas-fired resources, offset by the combination of a $13 million, or 15%, decrease in energy generated from Company-owned coal-fired resources and an $18 million, or 5%, reduction in energy received from purchased power. The increase in natural gas-fired generation was due primarily to the replacement of energy received from higher cost resources and reflects the addition of Carty in July 2016.

In 2016, energy received from PGE-owned wind generating resources (Biglow Canyon and Tucannon River) increased 7% from 2015 due to more favorable wind conditions, and represented 10% of the Company's retail load requirement in 2016 compared with 9% in 2015. As a result of improved hydro conditions in the region, energy received from PGE-owned hydroelectric projects and from mid-Columbia projects combined for 2016 was 5% above 2015 levels, and represented 17% of the Company's retail load requirement for 2016 and 16% for 2015.

The following table presents the forecast of the April-to-September 2017 runoff (as of February 9, 2017) compared to the actual runoffs for 2016 and 2015:

	Runoff as a Percent of Normal *		
Location	**2017 Forecast**	**2016 Actual**	**2015 Actual**
Columbia River at The Dalles, Oregon	99%	89%	69%
Mid-Columbia River at Grand Coulee, Washington	95	91	77
Clackamas River at Estacada, Oregon	101	71	53
Deschutes River at Moody, Oregon	98	91	85

* Volumetric water supply forecasts and historical 30-year averages for the Pacific Northwest region are prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies.

Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, decreased $59 million for 2016 compared with 2015. The decrease attributable to changes in Purchased power and fuel expense was the result of an 8% decline in the average variable power cost per MWh, offset slightly by a 1% increase in total system load. The decrease in actual NVPC was also driven by a 31% increase in the volume of wholesale energy deliveries as the Company's retail load requirement decreased in 2016, largely due to the effects of weather, which resulted in a greater portion of its system load being sold into the wholesale market. The increase was partially offset by an 11% decrease in the average price per MWh of wholesale power sales. The 2016 GRC had anticipated a decrease of approximately $31 million in NVPC from the 2015 baseline, with customer prices set accordingly.

For 2016, actual NVPC, as calculated for regulatory purposes under the PCAM, was $10 million below the 2016 baseline NVPC. In 2015, NVPC was $3 million below the anticipated baseline. For further information regarding NVPC, see *"Power Operations"* in the Overview section of this Item 7.

Generation, transmission, and distribution expense increased $20 million, or 8%, in 2016 compared with 2015. The increase was driven by the combination of $7 million in higher costs due to the addition of Carty, $5 million higher service restoration and storm costs, $4 million higher information technology expenses, $4 million higher inspection and testing costs for the distribution system, $2 million higher plant maintenance expenses, and $2 million higher labor expense. Partially offsetting the increases was a reduction in expenses of $6 million due to the repair and maintenance work during the annual planned outage and economic displacement of Boardman in 2015.

Administrative and other expense increased $6 million, or 2%, in 2016 compared with 2015, primarily due to $5 million higher legal costs attributable to Carty. The Company experienced slightly higher overall labor and employee benefit expenses although a $3 million reduction in pension expenses and a $2 million reduction in injuries and damages expense offset a large portion of those increases.

Depreciation and amortization expense in 2016 increased $16 million, or 5%, compared with 2015. The increase was primarily driven by $20 million higher expense resulting from capital additions, a $7 million expense increase resulting from the amortization credits in 2015 from gains recorded on the sale of assets, and a $5 million expense increase from lower amortization credits in 2016 of the regulatory liability for the ISFSI tax credits, offset by a $19 million expense decrease that resulted from the completion at the end of 2015 of the amortization of the regulatory asset related to the four capital projects deferral as authorized in the Company's 2011 GRC. The overall impact resulting from the amortization of the regulatory assets and liabilities is directly offset by corresponding reductions in retail revenues.

Taxes other than income taxes expense increased $3 million, or 3%, in 2016 compared with 2015, as higher property valuations in the State of Oregon increased taxes by $4 million, which was partially offset by lower property tax rates in both Oregon and Washington.

Interest expense decreased $2 million, or 2%, in 2016 compared with 2015 with $4 million lower expense resulting from a 3% decrease in the average balance of debt outstanding, partially offset by $2 million less allowance for borrowed funds used during construction credits.

Other income, net was $22 million in both 2016 and 2015, comprised primarily of $21 million in the allowance for equity funds used during construction each year, driven by the construction of Carty.

Income tax expense increased $5 million, or 11%, in 2016 compared to 2015. Higher pre-tax income accounted for a $10 million increase, which was partially offset by a $3 million increase in production tax credits and a combination of state credits and tax deductions that reduced expense by $2 million.

2015 Compared to 2014

Revenues decreased $2 million, or less than 1%, in 2015 compared with 2014 as a result of the items discussed below.

Total retail revenues increased $12 million, or 1%, in 2015 compared with 2014, primarily due to the net effect of the following:

- An $11 million increase in revenues related to a 0.6% increase in retail energy deliveries, consisting of 5.5% and 0.2% increases in industrial and commercial deliveries, respectively, partially offset by a 1.8% decrease in residential deliveries; and
- A $4 million net increase that related to higher average retail prices resulting from the January 1, 2015 price increase authorized by the OPUC in the Company's 2015 GRC, which was net of a $28 million decrease due to various supplemental tariff changes, including $20 million in customer credits in 2015 related to proceeds received in connection with the settlement of a legal matter regarding the operation of the ISFSI at the former Trojan nuclear power plant site and tax credits, all of which are offset in Depreciation and Amortization expense.

Total heating degree-days in 2015 were lower than the 15-year average (as provided by the National Weather Service, as measured at Portland International Airport) and total heating degree-days in 2014, while total cooling degree-days in 2015 exceeded the 15-year average and 2014 total cooling degree-days. The following table presents the number of heating and cooling degree-days in 2015 and 2014, along with the 15-year averages:

	Heating Degree-Days			**Cooling Degree-Days**		
	2015	**2014**	**15-Year Average**	**2015**	**2014**	**15-Year Average**
1st quarter	1,481	1,891	1,864	—	—	—
2nd quarter	513	530	713	207	57	70
3rd quarter	76	18	85	573	579	382
4th quarter	1,391	1,355	1,602	5	17	1
Total	3,461	3,794	4,264	785	653	453
Increase (decrease) from the 15-year average	(19)%	(11)%		73%	44%	

On a weather adjusted basis, retail energy deliveries in 2015 were 2.3% above 2014.

Wholesale revenues in 2015 decreased $7 million, or 7%, from 2014, with such decrease comprised of $8 million related to a 9% lower average wholesale market prices partially offset by a $2 million increase related to 2% greater wholesale sales volume.

Other operating revenues decreased $7 million, or 17%, in 2015 from 2014, primarily due to a $4 million decline in high voltage service revenues and a $3 million decrease in transmission resale revenues. Resale of excess natural gas and oil needed for operations was comparable in 2015 to 2014.

Purchased power and fuel expense in 2015 decreased $52 million, or 7%, from 2014, driven by a $57 million, or 8%, decline related to the decrease in the average variable power cost per MWh to $30.91 in 2015 from $33.54 in 2014, partially offset by a $5 million increase resulting from a 1% increase in total system load.

As a result of below normal hydro conditions in the region, energy received from PGE-owned hydroelectric projects and from mid-Columbia projects combined for 2015 was 9% below 2014 levels, and represented 16% of the Company's retail load requirement for 2015 and 18% in 2014. Total hydroelectric energy received from these sources fell short of that projected in PGE's AUT by approximately 7% for 2015 and 2% for 2014.

The following table presents the actual of the April-to-September runoff for 2015 and 2014:

	Runoff as a Percent of Normal *	
Location	**2015 Actual**	**2014 Actual**
Columbia River at The Dalles, Oregon	69%	108%
Mid-Columbia River at Grand Coulee, Washington	77	110
Clackamas River at Estacada, Oregon	53	97
Deschutes River at Moody, Oregon	85	98

* Actual volumetric water supply amounts and historical 30-year averages for the Pacific Northwest region are prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies.

In 2015, energy received from PGE-owned wind generating resources (Biglow Canyon and Tucannon River, which was placed in service during December 2014) increased 53% from 2014, and represented 9% of the Company's retail load requirement in 2015 compared to 6% in 2014. Energy received from wind generating resources fell short of projections included in the Company's AUT by approximately 15% in 2015 compared with 9% in 2014.

Actual NVPC decreased $45 million for 2015 compared with 2014. The decrease was largely due to an 8% decline in the average variable power cost per MWh combined with a 2% increase in the volume of wholesale power sales, net of a 9% decrease in the average price per MWh of wholesale power sales. The 2015 GRC had anticipated a decrease of approximately $60 million in NVPC from the 2014 baseline, with customer prices set accordingly. For 2015, actual NVPC, as calculated for regulatory purposes under the PCAM, was $3 million below baseline NVPC, compared with $7 million below for 2014.

Generation, transmission, and distribution expense increased $9 million, or 4%, in 2015 compared with 2014. The increase was driven by the combination of $9 million higher costs due to the addition of PW2 and Tucannon River, $3 million higher information technology expenses, $2 million higher plant maintenance expenses, increased outside services of $2 million, higher labor of $2 million, and higher service restoration and storm costs of $2 million. Partially offsetting the increases were lower expense of $8 million related to repair and maintenance work during the annual planned outage and economic displacement of Boardman in 2015, coupled with the unplanned outages at Colstrip in January 2014, and $3 million lower expenses related to high voltage customer services.

Administrative and other expense increased $14 million, or 6%, in 2015 compared with 2014, primarily due to a $5 million increase in information technology expenses, an increase of $3 million in non-labor and outside services expenses, a $3 million increase in injuries and damages resulting from insurance recoveries related to prior year claims received in 2014, and a $1 million increase in compensation and benefits expense.

Depreciation and amortization expense in 2015 increased $4 million, or 1%, compared with 2014. A $26 million higher expense resulting from capital additions was largely offset by a $22 million reduction from the amortization of deferred regulatory liabilities for the Trojan spent fuel settlement and tax credits as they were refunded to customers in 2015. An increase in asset retirement obligations (AROs) expenses and amortization of costs previously deferred for four capital projects as authorized in the Company's 2011 GRC were partially offset by amortization of gains recorded on the sale of assets. The overall reduction in expenses resulting from the amortization of the regulatory liabilities is directly offset by corresponding reductions in retail revenues.

Taxes other than income taxes expense increased $7 million, or 6%, in 2015 compared with 2014, primarily due to a $5 million increase in property taxes attributed to the addition of PW2 and Tucannon River and a $2 million increase in franchise fees.

Interest expense increased $18 million, or 19%, in 2015 compared to 2014 as $9 million resulted from lower allowance for borrowed funds used during construction. In December 2014, PW2 and Tucannon River were placed into service resulting in a lower average CWIP balance, the basis for AFDC, during 2015. In addition, $7 million related to a 7% increase in the average balance of debt outstanding.

Other income, net was $22 million in 2015 compared to $38 million in 2014. The decrease was primarily due to a $16 million decrease in the allowance for equity funds used during construction resulting from the lower average CWIP balance.

Income tax expense decreased $16 million, or 26%, in 2015 compared with 2014, while the effective tax rate decreased to 20.7% for 2015 from 26.0% for 2014. Lower pre-tax income accounted for $7 million of the decrease in income tax expense. A $14 million increase in PTCs in 2015, resulting primarily from the addition of Tucannon River wind generation, was partially offset by a $5 million relative effect of lower AFDC equity.

Liquidity and Capital Resources

Discussions, forward-looking statements, and projections in this section, and similar statements in other parts of this Annual Report on Form 10-K, are subject to PGE's assumptions regarding the availability and cost of capital. See *"Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently envisioned."* in Item 1A.—Risk Factors, for further information.

Capital Requirements

The following table presents actual capital expenditures and debt maturities for 2016 and projected capital expenditures and future debt maturities for 2017 through 2021 (in millions, excluding AFDC):

	Years Ending December 31,					
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Ongoing capital expenditures	$ 406	$ 604	$ 427	$ 294	$ 300	$ 290
Carty	190	6	—	—	—	—
Total capital expenditures	$ 596 *	$ 610	$ 427	$ 294	$ 300	$ 290
Long-term debt maturities	$ —	$ 150	$ —	$ 300	$ —	$ 160

* Amounts shown include preliminary engineering and removal costs, which are included in other net operating activities in the consolidated statements of cash flows.

For a discussion concerning PGE's ability to fund its future capital requirements, see "*Debt and Equity Financings*" in this Item 7.

Ongoing capital expenditures—This line in the table above consists primarily of upgrades to, and replacement of, generation, transmission, distribution infrastructure, as well as new customer connections. For the years 2017 through 2018, approximately $63 million relates to the implementation of the Company's new customer information and meter data management systems. In addition, $149 million is included for transmission, distribution, and generation resiliency projects in 2017.

Carty—On July 29, 2016, Carty, a natural gas-fired baseload resource in Eastern Oregon, was placed into service. As of December 31, 2016, PGE had $634 million in plant in service related to Carty. The Company expects to incur certain trailing costs in 2017 that could amount to $6 million and currently estimates that the total capital expenditures for Carty will be approximately $640 million, including AFDC. This estimate excludes approximately $17 million of lien claims filed against PGE for goods and services provided under contracts with the former Contractor. The Company believes these liens are invalid and is contesting the claims in the courts. Estimated total expenditures for Carty would be offset by any amounts received from the Sureties pursuant to the performance bond. For additional information, see *"Carty"* in the Overview section in Item 7.

Liquidity

PGE's access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company's current operating activities, including the purchase of power and fuel. Long-term capital requirements are driven largely by capital expenditures for distribution, transmission, and generation facilities to support both new and existing customers, information technology systems, and debt refinancing activities. PGE's liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposit requirements related to wholesale market activities, which can vary depending upon the Company's forward positions and the corresponding price curves.

The following summarizes PGE's cash flows for the periods presented (in millions):

	Years Ended December 31,		
	2016	**2015**	**2014**
Cash and cash equivalents, beginning of year	$ 4	$ 127	$ 107
Net cash provided by (used in):			
Operating activities	553	520	520
Investing activities	(585)	(522)	(994)
Financing activities	34	(121)	494
Net change in cash and cash equivalents	2	(123)	20
Cash and cash equivalents, end of year	$ 6	$ 4	$ 127

2016 Compared to 2015

Cash Flows from Operating Activities—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, including depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. The $33 million increase in cash flows from operating activities in 2016 compared to 2015 was largely due to increases in net income and depreciation expense, partly offset by the impact of changes in other non-cash income and expense items including amounts recorded under the decoupling mechanism, and a decrease in margin deposits. The remaining non-cash income and expenses and other components of working capital were fairly consistent year over year.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that such charges in 2017 will range from $340 million to $350 million. Combined with all other sources, cash provided by operations in 2017 is estimated to range from $450 million to $500 million.

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities. The $63 million increase in net cash used in investing activities in 2016 compared to 2015 was primarily due to a distribution of $50 million from the Nuclear decommissioning trust and $23 million the Company received from a sales tax refund related to Tucannon River, both in 2015. Capital expenditures decreased $14 million as

Carty was placed into service in July 2016. For additional information regarding the distribution from the Nuclear decommissioning trust, see Note 3, Balance Sheet Components, and Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

The Company plans for approximately $610 million of capital expenditures in 2017 related to upgrades to and replacement of generation, transmission, and distribution infrastructure. The planned amount reflects estimated capital expenditures to complete Carty of $6 million, excluding AFDC. PGE plans to fund the 2017 capital expenditures and current maturities of long-term debt of $150 million with cash from operations during 2017, as discussed above, as well as with the issuance of short- and long-term debt securities. For additional information, see "*Capital Requirements*" and "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2016, cash provided by financing activities consisted of the issuance of $290 million of long-term debt less the repayment $133 million of FMBs and dividends of $110 million, During 2015, cash used in financing activities consisted of repayments of long-term debt of $442 million and the payment of dividends of $97 million.

2015 Compared to 2014

Cash Flows from Operating Activities—Cash flows from operating activities in 2015 remained comparable to 2014. A decrease in the net change in working capital items and a decrease in the amount received from Bonneville Power Administration to be returned to customers pursuant to the Residential Exchange Program, which collectively, were nearly offset by an increase in the combination of Net income and non-cash income and expenses, net.

Cash Flows from Investing Activities—The $472 million decrease in net cash used in investing activities in 2015 compared to 2014 was primarily due to a $409 million decrease in capital expenditures, largely due to the completion of construction of PW2 and Tucannon River in December 2014. In addition, the Company received $23 million from a sales tax refund related to Tucannon River and a distribution of $50 million from the Nuclear decommissioning trust. For additional information regarding the distribution from the Nuclear decommissioning trust, see Note 3, Balance Sheet Components, and Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—“Financial Statements and Supplementary Data.”

Cash Flows from Financing Activities—During 2015, cash used in financing activities consisted of repayments of long-term debt of $442 million and the payment of dividends of $97 million, partially offset by net proceeds received from the issuances of common stock in the amount of $271 million and FMBs of $145 million. During 2014, net cash provided by financing activities consisted of net proceeds received from the issuances of term bank loans of $305 million and FMBs of $280 million, partially offset by the payment of dividends of $87 million.

Dividends on Common Stock

The following table presents common stock dividends declared in 2016:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 17, 2016	March 25, 2016	April 15, 2016	$ 0.30
April 27, 2016	June 27, 2016	July 15, 2016	0.32
July 27, 2016	September 26, 2016	October 17, 2016	0.32
October 26, 2016	December 27, 2016	January 17, 2017	0.32

While the Company expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. On February 15, 2017, a common stock dividend of $0.32 per share was declared, payable April 17, 2017 to shareholders of record on March 27, 2017. The amount of any dividend declaration will depend upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's and S&P, with current credit ratings and outlook as follows:

	Moody's	S&P
First Mortgage Bonds	A1	A-
Senior unsecured debt	A3	BBB
Commercial paper	Prime-2	A-2
Outlook	Stable	Stable

Should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt below investment grade, the Company could be subject to requests by certain of its wholesale, commodity, and transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. The performance assurance collateral can be in the form of cash deposits or letters of credit, depending on the terms of the underlying agreements, and are based on the contract terms and commodity prices and can vary from period to period. Cash deposits provided as collateral are classified as Margin deposits in PGE's consolidated balance sheet, while any letters of credit issued are not reflected in the Company's consolidated balance sheet.

As of December 31, 2016, PGE had posted approximately $25 million of collateral with these counterparties, consisting of $8 million in cash and $17 million in bank letters of credit, $11 million of which is related to master netting agreements. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2016, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $91 million and decreases to approximately $51 million by December 31, 2017 and $31 million by December 31, 2018. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $174 million and decreases to approximately $93 million by December 31, 2017 and $71 million by December 31, 2018.

PGE's financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade. However, the cost of borrowing and issuing letters of credit under the credit facilities would increase.

The Indenture securing PGE's outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. Interest is payable semi-annually on FMBs.

The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2016, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $1.2 billion of additional FMBs. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges, or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65% of total capitalization (debt to total capital ratio). As of December 31, 2016, the Company's debt to total capital ratio, as calculated under the credit agreements, was 51.0%.

Debt and Equity Financings

PGE's ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, its credit ratings, its capital expenditure requirements, alternatives available to investors, market conditions, and other factors. Management believes that the availability of revolving credit facilities, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient cash flow and liquidity to meet the Company's anticipated capital and operating requirements for the foreseeable future.

For 2017, PGE expects to fund estimated capital requirements with cash from operations, the issuance of debt securities of approximately $450 million, and the issuance of commercial paper, as needed. The actual timing and amount of any such issuances of debt or commercial paper will be dependent upon the timing and amount of capital expenditures.

Short-term Debt—PGE has approval from the FERC to issue short-term debt up to a total of $900 million through February 6, 2018.

As of December 31, 2016, PGE had a $500 million revolving credit facility scheduled to expire in November 2019. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and for general corporate purposes. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility.

PGE classifies any borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt in the consolidated balance sheets.

Under the revolving credit facility, as of December 31, 2016, PGE had no borrowings outstanding, and no commercial paper or letters of credit issued. As a result, as of December 31, 2016, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities under which the Company can request letters of credit for original terms not to exceed one year. These facilities provide for a total capacity of $160 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, letters of credit for a total of $56 million were outstanding as of December 31, 2016.

Long-term Debt—During 2016, PGE issued a total of $140 million and repaid $133 million of FMBs. In January 2016, the Company issued $140 million of 2.51% Series FMBs due 2021 and repaid $58 million of 3.81% Series FMBs, due in 2017 and $75 million of 5.80% series FMBs due in 2018. Due to the anticipated repayment of this $133 million in early January 2016, this amount of long-term debt was classified as current on the Company's consolidated balance sheets as of December 31, 2015.

In May 2016, PGE entered into an unsecured credit agreement with certain financial institutions, under which the Company had the opportunity to obtain three separate term loans in an aggregate principal amount of up to $200 million by October 31, 2016. Under the agreement, PGE obtained the following term loans:

- $50 million on May 4, 2016;
- $75 million on June 15, 2016; and
- $25 million on October 31, 2016.

The term loan interest rates are set at the beginning of the interest period for periods of 1-month, 3-months, or 6-months, as selected by PGE and are based on the London Interbank Offered Rate (LIBOR) plus 63 basis points, approximately 1.37% as of December 31, 2016, with no other fees.

The credit agreement expires November 30, 2017, at which time any amounts outstanding under the term loans become due and payable. As such, $150 million is reflected on the consolidated balance sheet as Current portion of long-term debt as of December 31, 2016. Upon the occurrence of certain events of default, the Company's obligations under the credit agreement may be accelerated. Such events of default include payment defaults to lenders under the credit agreement, covenant defaults, and other customary defaults for financings of this type.

As of December 31, 2016, total long-term debt outstanding, net of $11 million unamortized debt expense, was $2,350 million, of which $150 million of the term loans are scheduled to mature in 2017.

Capital Structure—PGE's financial objectives include maintaining a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50% over time. Achievement of this objective helps the Company maintain investment grade debt ratings and provides access to long-term capital at favorable interest rates. The Company's common equity ratios were 49.4% and 50.7% as of December 31, 2016 and 2015, respectively.

Contractual Obligations and Commercial Commitments

The following table presents PGE's contractual obligations as of December 31, 2016 (in millions):

	2017	2018	2019	2020	2021	There-after	Total
Long-term debt	$ 150	$ —	$ 300	$ —	$ 160	$ 1,751	$ 2,361
Interest on long-term debt (1)	116	114	101	95	91	1,530	2,047
Capital and other purchase commitments	176	8	2	9	1	60	256
Purchased power and fuel:							
Electricity purchases	221	157	181	256	239	1,750	2,804
Capacity contracts	7	6	5	4	4	12	38
Public Utility Districts	4	4	1	—	1	11	21
Natural gas	53	39	32	27	24	158	333
Coal and transportation	17	9	5	—	—	—	31
Pension Plan Contributions (2)	3	21	21	21	20	—	86
Capital leases	7	7	6	6	6	77	109
Build-to-suit lease	—	4	14	13	13	237	281
Operating leases	10	9	6	6	7	177	215
Total	$ 764	$ 378	$ 674	$ 437	$ 566	$ 5,763	$ 8,582

(1) Future interest on long-term debt is calculated based on the assumption that all debt remains outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect as of December 31, 2016.

(2) Contributions beyond 2021 are not estimated due to significant uncertainty in financial market and demographic outcomes.

Other Financial Obligations

PGE has entered into long-term power purchase agreements with certain public utility districts in the state of Washington under which it has acquired a percentage of the output of three hydroelectric projects (the Priest Rapids, Wanapum, and Wells hydroelectric projects). The Company is required to pay its proportionate share of the operating and debt service costs of the projects whether or not they are operable. The agreements further provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of both the output and the operating and debt service costs of the defaulting purchaser. For the Wells project, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage of the output. For the Priest Rapids and Wanapum projects, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any of the public utility district's outstanding debt for the portion of the project that benefits tax exempt purchasers. For additional information on these long-term power purchase agreements, see "*Public Utility Districts*" in Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Off-Balance Sheet Arrangements

PGE has no off-balance sheet arrangements other than outstanding letters of credit from time to time that have, or are reasonably likely to have, a material current or future effect on its consolidated financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources.

Critical Accounting Policies

The preparation of consolidated financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect amounts reported in the statements. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions, and judgments to determine matters that are inherently uncertain.

Regulatory Accounting

As a rate-regulated enterprise, PGE applies regulatory accounting, which includes the recognition of regulatory assets and liabilities on the Company's consolidated balance sheets. Regulatory assets represent probable future revenue associated with certain incurred costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited or refunded to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established or subject to approval by independent third-party regulators, prices are designed to recover the specific enterprise's cost of service, and, in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Amortization of regulatory assets and liabilities is reflected in the statement of income over the period in which they are included in customer prices.

If future recovery of regulatory assets is not probable, PGE would expense such items in the period such determination is made. Further, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of regulatory accounting, the Company would be required to write off those regulatory assets and liabilities related to operations that no longer meet requirements for regulatory accounting. Discontinued application of regulatory accounting would have a material impact on the Company's results of operations and financial position.

Asset Retirement Obligations

PGE recognizes AROs for legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. In estimating the liability, management must utilize significant judgment and assumptions in determining whether a legal obligation exists to remove assets. Other estimates may be related to lease provisions, ownership agreements, licensing issues, cost estimates, inflation, and certain legal requirements. Changes that may arise over time with regard to these assumptions and determinations can change future amounts recorded for AROs.

Capitalized asset retirement costs related to electric utility plant are depreciated over the estimated life of the related asset and included in Depreciation and amortization expense in the consolidated statements of income. Accretion of the ARO liability is classified as an operating expense in the consolidated statements of income. Accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from accumulated depreciation to regulatory liabilities in the consolidated balance sheets.

Revenue Recognition

Retail customers are billed monthly for electricity use based on meter readings taken throughout the month. At the end of each month, PGE estimates the revenue earned from the last meter read date through the last day of the month, which has not yet been billed to customers. Such amount, which is classified as Unbilled revenues in the Company's consolidated balance sheets, is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current customer prices.

Contingencies

PGE has various unresolved legal and regulatory matters about which there is inherent uncertainty, with the ultimate outcome contingent upon several factors. Such contingencies are evaluated using the best information available. A loss contingency is accrued, and disclosed if material, when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency and the reasons to the effect that it cannot be reasonably estimated are disclosed. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Established accruals reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the process. There can be no assurance as to the ultimate outcome of any particular contingency.

Price Risk Management

PGE engages in price risk management activities to manage exposure to commodity and foreign currency market fluctuations and to manage volatility in net power costs for its retail customers. The Company utilizes derivative instruments, which may include forward, futures, swap, and option contracts for electricity, natural gas, oil, and foreign currency. These derivative instruments are recorded at fair value, or "marked-to-market," in PGE's consolidated financial statements.

Fair value adjustments consist of reevaluating the fair value of derivative contracts at the end of each reporting period for the remaining term of the contract and recording any change in fair value in Net income for the period. Fair value is the present value of the difference between the contracted price and the forward market price multiplied by the total quantity of the contract. For option contracts, a theoretical value is calculated using Black-Scholes models that utilize price volatility, price correlation, time to expiration, interest rate and forward commodity price curves. The fair value of these options is the difference between the premium paid or received and the theoretical value at the fair value measurement date.

Determining the fair value of these financial instruments requires the use of prices at which a buyer or seller could currently contract to purchase or sell a commodity at a future date (termed "forward prices"). Forward price "curves" are used to determine the current fair market value of a commodity to be delivered in the future. PGE's forward price curves are created by utilizing actively quoted market indicators received from electronic and telephone brokers, industry publications, and other sources. Forward price curves can change with market conditions and can be materially affected by unpredictable factors such as weather and the economy. PGE's forward price curves are validated using broker quotes and market data from a regulated exchange and differences for any single location, delivery date, and commodity are less than 5%.

Pension Plan

Primary assumptions used in the actuarial valuation of PGE's pension plan include the discount rate, the expected return on plan assets, mortality rates, and wage escalation. These assumptions are evaluated by the Company, reviewed annually with the plan actuaries and trust investment consultants, and updated in light of market changes, trends, and future expectations. Significant differences between assumptions and actual experience can have a material impact on the valuation of the pension benefit plan obligation and net periodic pension cost.

PGE's pension discount rate is determined based on a portfolio of high-quality bonds that match the duration of the plan cash flows. The expected rate of return on plan assets is based on the projected long-term return on assets in the plan investment portfolio. PGE capitalizes a portion of pension expense based on the proportion of labor costs capitalized.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or reduction in the discount rate, would have the effect of increasing the 2016 net periodic pension expense by approximately $2 million.

Fair Value Measurements

PGE applies fair value measurements to its financial assets and liabilities, with fair value defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company’s financial assets and liabilities consist of: i) derivative instruments entered into in connection with its price risk management activities; ii) the majority of assets held by the Nuclear decommissioning trust, the Pension plan and the Non-qualified benefit plan trust; and iii) long-term debt. In valuing these items, the Company uses inputs and assumptions that market participants would use to determine their fair value, utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The determination of fair value can require subjective and complex judgment and PGE’s assessment of the inputs and the significance of a particular input to fair value measurement may affect the valuation of the instruments and their placement within the fair value hierarchy reported in its financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

PGE is exposed to various forms of market risk, consisting primarily of fluctuations in commodity prices, foreign currency exchange rates, and interest rates, as well as credit risk. Any variations in the Company’s market risk or credit risk may affect its future financial position, results of operations, or cash flows, as discussed below.

Risk Management Committee

PGE has a Risk Management Committee (RMC), which is responsible for providing oversight of the adequacy and effectiveness of corporate policies, guidelines, and procedures for market and credit risk management related to the Company’s energy portfolio management activities. The RMC consists of officers and Company representatives with responsibility for risk management, finance and accounting, legal, rates and regulatory affairs, power operations, generation operations, and business development. The RMC reviews and approves adoption of policies and procedures, and monitors compliance with policies, procedures, and limits on a regular basis through reports and meetings. The RMC also reviews and recommends risk limits that are subject to approval by PGE’s Board of Directors.

Commodity Price Risk

PGE is exposed to commodity price risk as its primary business is to provide electricity to its retail customers. The Company engages in price risk management activities to manage exposure to volatility in net power costs for its retail customers. The Company uses power purchase contracts to supplement its own generation and to respond to fluctuations in the demand for electricity and variability in generating plant operations. The Company also enters into contracts for the purchase of fuel for the Company’s natural gas- and coal-fired generating plants. These contracts for the purchase of power and fuel expose the Company to market risk. The Company uses instruments such as: forward contracts, which may involve physical delivery of an energy commodity; financial swap and futures agreements, which may require payments to, or receipt of payments from, counterparties based on the differential between a fixed and variable price for the commodity; and option contracts to mitigate risk that arises from market fluctuations of commodity prices. PGE does not engage in trading activities for non-retail purposes.

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2016 that are expected to settle in each respective year (in millions):

	2017	2018	2019	2020	2021	Thereafter	Total
Commodity contracts:							
Electricity	$ 6	$ 7	$ 7	$ 7	$ 7	$ 77	$ 111
Natural gas	20	7	6	2	—	—	35
	$ 26	$ 14	$ 13	$ 9	$ 7	$ 77	$ 146

PGE reports energy commodity derivative fair values as a net asset or liability, which combines purchases and sales expected to settle in the years noted above. Energy commodity fair values exposed to commodity price risk are primarily related to purchase contracts, which are slightly offset by sales.

PGE's energy portfolio activities are subject to regulation, with related costs included in retail prices approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation, significantly mitigating commodity price risk for the Company. As contracts are settled, these deferrals reverse and are recognized as Purchased power and fuel in the statements of income and included in the PCAM. PGE remains subject to cash flow risk in the form of collateral requirements based on the value of open positions and regulatory risk if recovery is disallowed by the OPUC. PGE attempts to mitigate both types of risks through prudent energy procurement practices.

Foreign Currency Exchange Rate Risk

PGE is exposed to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars in its energy portfolio. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE monitors its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy.

As of December 31, 2016, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

Interest Rate Risk

To meet short-term cash requirements, PGE has the ability to issue commercial paper for terms of up to 270 days and has a revolving credit facility that permits same day borrowings. Although any borrowings under the commercial paper program or the revolving credit facility carry a fixed rate during their respective terms, the short-term nature of such borrowings subjects the Company to fluctuations in interest rates that result from changes in market conditions. As of December 31, 2016, PGE had no borrowings outstanding under its revolving credit facility and no commercial paper outstanding or other short-term debt outstanding.

PGE currently has no financial instruments to mitigate risk related to changes in short-term interest rates, including those on commercial paper; however, it may consider such instruments in the future as considered necessary.

As of December 31, 2016, the total fair value and carrying amounts by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date					
		Total	2017	2018	2019	2020	There-after
First Mortgage Bonds	$ 2,411	$ 2,090	$ —	$ —	$ 300	$ —	$ 1,790
Unsecured Term Bank Loans	150	150	150	—	—	—	—
Pollution Control Revenue Bonds	132	121	—	—	—	—	121
Total	$ 2,693	$ 2,361	$ 150	$ —	$ 300	$ —	$ 1,911

As of December 31, 2016, PGE's unsecured term bank loans in the amount of $150 million were the only long-term debt instruments subject to interest rate risk exposures. As of December 31, 2016, a change of 10% in the existing interest rates of these unsecured term bank loans would result in an immaterial change in interest rate risk exposure over the next twelve months.

Credit Risk

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. PGE manages the risk of counterparty default according to its credit policies by performing financial credit reviews, setting limits and monitoring exposures, and requiring collateral (in the form of cash, letters of credit, and guarantees) when needed. The Company also uses standardized enabling agreements and, in certain cases, master netting agreements, which allow for the netting of positive and negative exposures under multiple agreements with counterparties. Despite such mitigation efforts, defaults by counterparties may periodically occur. Based upon periodic review and evaluation, allowances are recorded as needed to reflect credit risk related to wholesale accounts receivable.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, contribute to reduce credit risk with respect to trade accounts receivable from retail sales. Estimated provisions for uncollectible accounts receivable related to retail sales are provided for such risk.

As of December 31, 2016, PGE's credit risk exposure is $4 million for commodity activities with externally-rated investment grade counterparties and matures in 2018. The exposure is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Investment grade counterparties include those with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody's) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit, and may represent prepayment or credit exposure assurance.

Omitted from the market risk exposures discussed above are long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. These contracts provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2052. For additional information, see "*Public Utility Districts*" in Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The following financial statements and report are included in Item 8:

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Portland General Electric Company
Portland, Oregon

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2016. We also have audited the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 16, 2017

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in millions, except per share amounts)

	Years Ended December 31,		
	2016	**2015**	**2014**
Revenues, net	$ 1,923	$ 1,898	$ 1,900
Operating expenses:			
Purchased power and fuel	617	661	713
Generation, transmission and distribution	286	266	257
Administrative and other	247	241	227
Depreciation and amortization	321	305	301
Taxes other than income taxes	119	116	109
Total operating expenses	1,590	1,589	1,607
Income from operations	333	309	293
Interest expense, net	112	114	96
Other income:			
Allowance for equity funds used during construction	21	21	37
Miscellaneous income, net	1	1	1
Other income, net	22	22	38
Income before income taxes	243	217	235
Income tax expense	50	45	61
Net income	193	172	174
Less: net loss attributable to noncontrolling interests	—	—	(1)
Net income attributable to Portland General Electric Company	$ 193	$ 172	$ 175
Weighted-average shares outstanding (in thousands):			
Basic	88,896	84,180	78,180
Diluted	89,054	84,341	80,494
Earnings per share:			
Basic	$ 2.17	$ 2.05	$ 2.24
Diluted	$ 2.16	$ 2.04	$ 2.18

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Net income	$ 193	$ 172	$ 174
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of an immaterial amount in 2016 and 2015, and $2 in 2014	1	(1)	(2)
Comprehensive income	194	171	172
Less: comprehensive loss attributable to the noncontrolling interests	—	—	(1)
Comprehensive income attributable to Portland General Electric Company	$ 194	$ 171	$ 173

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	As of December 31,	
	2016	**2015**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6	$ 4
Accounts receivable, net	155	158
Unbilled revenues	107	95
Inventories, at average cost:		
Materials and supplies	50	44
Fuel	32	39
Regulatory assets—current	36	129
Other current assets	77	88
Total current assets	463	557
Electric utility plant:		
Generation	4,597	3,898
Transmission	521	451
Distribution	3,343	3,192
General	501	463
Intangible	572	556
Construction work-in-progress	213	545
Total electric utility plant	9,747	9,105
Accumulated depreciation and amortization	(3,313)	(3,093)
Electric utility plant, net	6,434	6,012
Regulatory assets—noncurrent	498	524
Nuclear decommissioning trust	41	40
Non-qualified benefit plan trust	34	33
Other noncurrent assets	57	44
Total assets	$ 7,527	$ 7,210

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued
(In millions, except share amounts)

	As of December 31,	
	2016	**2015**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 129	$ 98
Liabilities from price risk management activities—current	44	130
Short-term debt	—	6
Current portion of long-term debt	150	133
Accrued expenses and other current liabilities	254	259
Total current liabilities	577	626
Long-term debt, net of current portion	2,200	2,060
Regulatory liabilities—noncurrent	958	928
Deferred income taxes	669	632
Unfunded status of pension and postretirement plans	281	259
Liabilities from price risk management activities—noncurrent	125	161
Asset retirement obligations	161	151
Non-qualified benefit plan liabilities	105	106
Other noncurrent liabilities	107	29
Total liabilities	5,183	4,952
Commitments and contingencies (see notes)		
Equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding	—	—
Common stock, no par value, 160,000,000 shares authorized; 88,946,704 and 88,792,751 shares issued and outstanding as of December 31, 2016 and 2015, respectively	1,201	1,196
Accumulated other comprehensive loss	(7)	(8)
Retained earnings	1,150	1,070
Total equity	2,344	2,258
Total liabilities and equity	$ 7,527	$ 7,210

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(In millions, except share and per share amounts)

	Portland General Electric Company Shareholders' Equity				
	Common Stock				
	Shares	Amount	Accumulated Other Comprehensive Loss	Retained Earnings	Noncontrolling Interests' Equity
Balance as of December 31, 2013	78,085,559	$ 911	$ (5)	$ 913	$ 1
Shares issued pursuant to equity-based plans	142,780	1	—	—	—
Stock-based compensation	—	6	—	—	—
Dividends declared ($1.115 per share)	—	—	—	(88)	—
Net income (loss)	—	—	—	175	(1)
Other comprehensive (loss)	—	—	(2)	—	—
Balance as of December 31, 2014	78,228,339	918	(7)	1,000	—
Issuances of common stock, net of issuance costs of $12	10,400,000	271			
Shares issued pursuant to equity-based plans	164,412	1	—	—	—
Stock-based compensation	—	6	—	—	—
Dividends declared ($1.18 per share)	—	—	—	(102)	—
Net income	—	—	—	172	—
Other comprehensive (loss)	—	—	(1)	—	—
Balance as of December 31, 2015	88,792,751	1,196	(8)	1,070	—
Shares issued pursuant to equity-based plans	153,953	1	—	—	—
Stock-based compensation	—	4	—	—	—
Dividends declared ($1.26 per share)	—	—	—	(113)	—
Net income	—	—	—	193	—
Other comprehensive income	—	—	1	—	—
Balance as of December 31, 2016	88,946,704	$ 1,201	$ (7)	$ 1,150	$ —

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Cash flows from operating activities:			
Net income	$ 193	$ 172	$ 174
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	321	305	301
Deferred income taxes	37	40	39
Allowance for equity funds used during construction	(21)	(21)	(37)
Pension and other postretirement benefits	28	34	33
Regulatory deferral of settled derivative instruments	2	2	10
Unrealized losses on non-qualified benefit plan trust assets	5	6	7
Decoupling mechanism deferrals, net of amortization	(6)	14	6
Other non-cash income and expenses, net	5	20	14
Changes in working capital:			
(Increase) decrease in receivables and unbilled revenues	(9)	(11)	8
Decrease (increase) in margin deposits	25	(22)	(2)
Increase (decrease) in payables and accrued liabilities	15	6	(13)
Other working capital items, net	(4)	(4)	(12)
Cash received to be returned to customers pursuant to the Residential Exchange Program, net of amortization	(6)	(1)	13
Contribution to non-qualified employee benefit trust	(10)	(9)	(8)
Contribution to voluntary employees’ benefit association trust	(2)	(4)	(3)
Other, net	(20)	(7)	(10)
Net cash provided by operating activities	553	520	520
Cash flows from investing activities:			
Capital expenditures	(584)	(598)	(1,007)
Purchases of nuclear decommissioning trust securities	(25)	(19)	(19)
Sales of nuclear decommissioning trust securities	27	22	17
Distribution from (contribution to) nuclear decommissioning trust	—	50	(6)
Sales tax refund received - Tucannon River Wind Farm	—	23	—
Cash received in connection with purchase of 10% interest in Boardman, net of cash paid	—	—	8
Other, net	(3)	—	13
Net cash used in investing activities	(585)	(522)	(994)

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(In millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 290	$ 145	$ 585
Payments on long-term debt	(133)	(442)	—
Proceeds from issuances of common stock, net of issuance costs	—	271	—
(Maturities) issuances of commercial paper, net	(6)	6	—
Dividends paid	(110)	(97)	(87)
Other	(7)	(4)	(4)
Net cash provided by (used in) financing activities	34	(121)	494
Increase (decrease) in cash and cash equivalents	2	(123)	20
Cash and cash equivalents, beginning of year	4	127	107
Cash and cash equivalents, end of year	$ 6	$ 4	$ 127
Supplemental disclosures of cash flow information:			
Cash paid for:			
Interest, net of amounts capitalized	$ 104	$ 108	$ 86
Income taxes	16	3	22
Non-cash investing and financing activities:			
Accrued capital additions	50	32	70
Accrued dividends payable	30	28	23
Accrued sales tax refund related to Tucannon River Wind Farm	—	—	23
Assets obtained under leasing arrangements	78	—	—

See accompanying notes to consolidated financial statements.

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) is a single, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company's corporate headquarters is located in Portland, Oregon and its approximately 4,000 square mile, state-approved service area is located entirely within the State of Oregon. PGE's allocated service area includes 51 incorporated cities, of which Portland and Salem are the largest. As of December 31, 2016, PGE served approximately 863,000 retail customers with a service area population of approximately 1.9 million, comprising approximately 46% of the population of the state.

As of December 31, 2016, PGE had 2,752 employees, with 783 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 730 and 53 employees and expire March 2020 and August 2017, respectively.

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC) with respect to retail prices, utility services, accounting policies and practices, issuances of securities, and certain other matters. Retail prices are based on the Company's cost to serve customers, including an opportunity to earn a reasonable rate of return, as determined by the OPUC. The Company is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in matters related to wholesale energy transactions, transmission services, reliability standards, natural gas pipelines, hydroelectric project licensing, accounting policies and practices, short-term debt issuances, and certain other matters.

Consolidation Principles

The consolidated financial statements include the accounts of PGE, its wholly-owned subsidiaries, and those variable interest entities (VIEs) in which PGE has determined it is the primary beneficiary. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in its consolidated financial statements. For further information on PGE's jointly-owned plant, see Note 16, Jointly-Owned Plan. Intercompany balances and transactions have been eliminated.

For entities that are determined to meet the definition of a VIE and in which the Company has determined it is the primary beneficiary, the VIE is consolidated and a noncontrolling interest is recognized for any third party interests. This has resulted in the Company consolidating entities in which it has less than a 50% equity interest. There were no material VIEs in 2016 or 2015.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of gain or loss contingencies, as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

Reclassifications

To conform with the 2016 presentation, PGE has reclassified Proceeds received from Trojan spent fuel legal settlement of $6 million to Other, net within the operating activities section, and Proceeds received from insurance recoveries of $3 million and Proceeds from sale of properties of $5 million to Other, net within the investing activities section of the consolidated statement of cash flows for the year ended December 31, 2014.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents, of which PGE had $1 million as of December 31, 2016 and none as of December 31, 2015 included within Cash and cash equivalents in the consolidated balance sheets.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts based on prices that are subject to federal (FERC) and state (OPUC) regulations. Balances do not bear interest; however, late fees are assessed beginning 16 business days after the invoice due date. Accounts that are inactivated due to nonpayment are charged-off in the period in which the receivable is deemed uncollectible, but no sooner than 45 business days after the due date of the final invoice.

Provisions for uncollectible accounts receivable related to retail sales are charged to Administrative and other expense and are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates are based on management’s assessment of the probability of collection, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Provisions for uncollectible accounts receivable related to wholesale sales are charged to Purchased power and fuel expense and are recorded periodically based on a review of counterparty non-performance risk and contractual right of offset when applicable. There have been no material write-offs of accounts receivable related to wholesale sales in 2016, 2015, and 2014.

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, future, swap, and option contracts for electricity, natural gas, oil, and foreign currency. These instruments are measured at fair value and recorded on the consolidated balance sheets as assets or liabilities from price risk management activities. Changes in fair value are recognized in the consolidated statement of income, offset by the effects of regulatory accounting. Certain electricity forward contracts that were entered into in anticipation of serving the Company’s regulated retail load may meet the requirements for treatment under the normal purchases and normal sales scope exception. Such contracts are not recorded at fair value and are recognized under accrual accounting.

Price risk management activities are utilized as economic hedges to protect against variability in expected future cash flows due to associated price risk and to manage exposure to volatility in net power costs for the Company’s retail customers.

In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer unrealized losses or gains, respectively, on derivative instruments until settlement. At the time of settlement, PGE recognizes a realized gain or loss on the derivative instrument.

Electricity and natural gas sale and purchase transactions that are physically settled are recorded in Revenues and Purchased power and fuel expense upon settlement, respectively, while transactions that are not physically settled (financial transactions) are recorded on a net basis in Purchased power and fuel expense upon financial settlement.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral with certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are included within Other current assets in the consolidated balance sheets and were $8 million and $33 million as of December 31, 2016 and 2015, respectively. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheet and were $17 million and $63 million as of December 31, 2016 and 2015, respectively.

Inventories

PGE's inventories, which are recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance, and capital activities, as well as fuel for use in its generating plants. Fuel inventories include natural gas, coal, and oil. Periodically, the Company assesses the realizability of inventory for purposes of determining that inventory is recorded at the lower of average cost or market.

Electric Utility Plant

Capitalization Policy

Electric utility plant is capitalized at its original cost, which includes direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and an allowance for funds used during construction (AFDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Periodic major maintenance inspections and overhauls at the Company's generating plants are charged to expense as incurred, subject to regulatory accounting as applicable. Costs to purchase or develop software applications for internal use only are capitalized and amortized over the estimated useful life of the software. Costs of obtaining a FERC license for the Company's hydroelectric projects are capitalized and amortized over the related license period.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as Construction work-in-progress (CWIP) in Electric utility plant on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, the Company may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. Costs disallowed for recovery in customer prices, if any, are charged to expense at the time such disallowance becomes probable.

PGE records AFDC, which is intended to represent the Company's cost of funds used for construction purposes, based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. AFDC is capitalized as part of the cost of plant and credited to the consolidated statements of income. The average rate used by PGE was 7.3% in 2016 and 2015, and 7.4% in 2014. AFDC from borrowed funds was $11 million in 2016, $13 million in 2015, and $22 million in 2014 and is reflected as a reduction to Interest expense. AFDC from equity funds, included in Other income, net, was $21 million in 2016 and 2015, and $37 million in 2014.

On July 29, 2016, PGE placed Carty into service, a baseload natural gas-fired generating plant in Eastern Oregon, located adjacent to the Boardman coal-fired generating plant (Boardman). As of December 31, 2016, PGE had $634 million included in Electric utility plant for Carty. On November 3, 2015, the OPUC issued an order approving settlements reached in PGE's 2016 GRC filing, including capital costs of up to $514 million, including AFDC, for Carty and that Carty would be included in customer prices when the plant was placed in service, provided that occurred by July 31, 2016. As Carty was placed in service on July 29, 2016, the Company has been authorized to include in customer prices, effective August 1, 2016, the revenue requirement necessary to allow for recovery of capital costs of up to $514 million, as well as Carty's operating costs. See Note 17, Contingencies, for further information regarding Carty.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was 3.5% in 2016, and 3.6% in 2015 and 2014. A component of depreciation expense includes estimated asset retirement removal costs allowed in customer prices.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (AROs) and asset retirement removal costs. The studies are conducted at a minimum of every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. The most recent depreciation study was completed for 2013, with an order received from the OPUC in September 2014 authorizing new depreciation rates effective January 1, 2015. In December 2016, a depreciation study was completed, which will be incorporated into the Company's planned 2018 general rate case to be filed with the OPUC by the end of February 2017.

Thermal generation plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the estimated retirement dates, which range from 2020 to 2059. Depreciation is provided on the Company's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Generation, excluding thermal:	
Hydro	95
Wind	30
Transmission	57
Distribution	45
General	12

When property is retired and removed from service, the original cost of the depreciable property units, net of any related salvage value, is charged to accumulated depreciation. Cost of removal expenditures are recorded against AROs or to accumulated asset retirement removal costs, if applicable, and included in Regulatory liabilities.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $257 million and $227 million as of December 31, 2016 and 2015, respectively, with amortization expense of $44 million in 2016, and $38 million in 2015 and $25 million in 2014. Future estimated amortization expense as of December 31, 2016 is as follows: $45 million in 2017; $44 million in 2018; $38 million in 2019; $34 million in 2020; and $22 million in 2021.

Marketable Securities

All of PGE's investments in marketable securities, included in the Non-qualified benefit plan trust and Nuclear decommissioning trust on the consolidated balance sheets, are classified as trading. These securities are classified as noncurrent because they are not available for use in operations. Trading securities are stated at fair value based on quoted market prices. Realized and unrealized gains and losses on the Non-qualified benefit plan trust assets are included in Other income, net. Realized and unrealized gains and losses on the Nuclear decommissioning trust fund assets are recorded as regulatory liabilities or assets, respectively, for future ratemaking treatment. The cost of securities sold is based on the average cost method.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, PGE applies regulatory accounting, which results in the creation of regulatory assets and regulatory liabilities. Regulatory assets represent: i) probable future revenue associated with certain actual or estimated costs that are expected to be recovered from customers through the ratemaking process; or ii) probable future collections from customers resulting from revenue accrued for completed alternative revenue programs, provided certain criteria are met. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory accounting is appropriate as long as: prices are established by, or subject to, approval by independent third-party regulators; prices are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Once the regulatory asset or liability is reflected in prices, the respective regulatory asset or liability is amortized to the appropriate line item in the consolidated statement of income over the period in which it is included in prices.

Circumstances that could result in the discontinuance of regulatory accounting include: i) increased competition that restricts the Company's ability to establish prices to recover specific costs; and ii) a significant change in the manner in which prices are set by regulators from cost-based regulation to another form of regulation. PGE periodically reviews the criteria of regulatory accounting to ensure that its continued application is appropriate. Based on a current evaluation of the various factors and conditions, management believes that recovery of the Company's regulatory assets is probable.

For additional information concerning the Company's regulatory assets and liabilities, see Note 6, Regulatory Assets and Liabilities.

Power Cost Adjustment Mechanism

PGE is subject to a power cost adjustment mechanism (PCAM) as approved by the OPUC. Pursuant to the PCAM, the Company can adjust future customer prices to reflect a portion of the difference between each year's forecasted net variable power costs (NVPC) included in customer prices (baseline NVPC) and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC by application of an asymmetrical "deadband," which ranges from $15 million below to $30 million above baseline NVPC. NVPC consists of i) the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts, all of which is classified as Purchased power and fuel in the Company's consolidated statements of income; and is net of ii) wholesale sales, which are classified as Revenues, net in the consolidated statements of income.

To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from or refunded to customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 9.6% for 2016, 9.68% for 2015, and 9.75% for 2014.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues in the Company's consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense. A final determination of any customer refund or collection is made in the following year by the OPUC through a public filing and review. The PCAM has resulted in no collection from, or refund to, customers since 2011.

Asset Retirement Obligations

Legal obligations related to the future retirement of tangible long-lived assets are classified as AROs on PGE's consolidated balance sheet. An ARO is recognized in the period in which the legal obligation is incurred, and when the fair value of the liability can be reasonably estimated. Due to the long lead time involved until decommissioning activities occur, the Company uses present value techniques because quoted market prices and a market-risk premium are not available. The present value of estimated future dismantlement and restoration costs is capitalized and included in Electric utility plant, net on the consolidated balance sheets with a corresponding offset to ARO. Such estimates are revised periodically, with actual expenditures charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, which is included in Depreciation and amortization in the consolidated statements of income. Changes in the ARO resulting from the passage of time (accretion) is based on the original discount rate and recognized as an increase in the carrying amount of the liability and as a charge to accretion expense, which is classified as Depreciation and amortization expense in the Company's consolidated statements of income.

For additional information concerning the Company's AROs, see Note 7, Asset Retirement Obligations.

The difference between the timing of the recognition of the AROs' depreciation and accretion expenses and the amount included in customers' prices is recorded as a regulatory asset or liability in the Company's consolidated balance sheets. PGE had a regulatory liability related to AROs in the amount of $49 million as of December 31, 2016 and $45 million as of December 31, 2015. For additional information concerning the Company's regulatory liability related to AROs, see Note 6, Regulatory Assets and Liabilities.

Contingencies

Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. Loss contingencies are accrued, and disclosed if material, when it is probable that an asset has been impaired or a liability incurred as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.
A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be reasonably estimated, disclosure of the loss contingency includes a statement to that effect and the reasons.

If an asset has been impaired or a liability incurred after the financial statement date, but prior to the issuance of the financial statements, the loss contingency is disclosed, if material, and the amount of any estimated loss is recorded in the subsequent reporting period.

Gain contingencies are recognized when realized and are disclosed when material.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss (AOCL) presented on the consolidated balance sheets is comprised of the difference between the non-qualified benefit plans' obligations recognized in net income and the unfunded position.

Revenue Recognition

Revenues are recognized as electricity is delivered to customers and include amounts for any services provided. The prices charged to customers are subject to federal (FERC) or state (OPUC) regulation. Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $43 million in 2016 and 2015, and $42 million in 2014.

Retail revenue is billed monthly based on meter readings taken throughout the month. Unbilled revenue represents the revenue earned from the time of the last meter read date through the last day of the month, a period that has not been billed as of the last day of the month. Unbilled revenue is calculated based on actual net retail system load each month, the number of days from the last meter read date through the last day of the month, and current retail customer prices.

As a rate-regulated utility, PGE, in certain situations, recognizes revenue to be billed to customers in future periods or defers the recognition of certain revenues to the period in which the related costs are incurred or approved by the OPUC for amortization. For additional information, see "*Regulatory Assets and Liabilities*" in this Note 2.

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite vesting period. PGE attributes the value of stock-based compensation to expense on a straight-line basis. For additional information concerning the Company's Stock-Based Compensation, see Note 13, Stock-Based Compensation Expense.

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Any valuation allowance would be established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

Because PGE is a rate-regulated enterprise, changes in deferred tax assets and liabilities that are related to certain property are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. Such amounts were recognized as net regulatory assets of $86 million as of December 31, 2016 and as of 2015 and will be included in prices when the temporary differences reverse.

Unrecognized tax benefits represent management's expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are no longer considered uncertain, PGE would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's consolidated balance sheet.

PGE records any interest and penalties related to income tax deficiencies in Interest expense and Other income, net, respectively, in the consolidated statements of income.

Recent Accounting Pronouncements

Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers* (Topic 606) (ASU 2014-09), creates a new Topic 606 and supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and most industry-specific guidance throughout the Industry Topics of the Codification. ASU 2014-09 provides a five-step analysis of transactions to determine when and how revenue is recognized that consists of: i) identify the contract with the customer; ii) identify the performance obligations in the contract; iii) determine the transaction price; iv) allocate the transaction price to the performance obligations; and v) recognize revenue when or as each performance obligation is satisfied. Companies can transition to the requirements of this ASU either retrospectively (full retrospective method) or as a cumulative-effect adjustment as of the effective date (modified retrospective method), which is January 1, 2018 for calendar year-end public entities. The Company is evaluating which transition method it will elect. The Company does not anticipate any material changes to its revenue policy for tariff-based revenues, which comprises a majority of PGE’s retail revenues, as performance obligations are expected to be satisfied in a similar recognition pattern. PGE continues to evaluate the impacts the new guidance may have on its consolidated financial position, consolidated results of operations, and consolidated cash flows, particularly related to recognizing revenue for certain contracts where collectibility may be in question, the extent to which certain transactions such as contributions in aid of construction (CIAC) are within the scope of the standard, certain matters of presentation of alternative revenue programs (such as decoupling), wholesale, and other operating revenue contracts.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* which supersedes the current lease accounting requirements for lessees and lessors within Topic 840, *Leases*. Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases, on the balance sheet and record corresponding right-of-use assets and lease liabilities. Accounting for lessors is substantially unchanged from current accounting principles. Lessees will be required to classify leases as either finance leases or operating leases. Initial balance sheet measurement is similar for both types of leases; however, expense recognition and amortization of right-of-use assets will differ. Operating leases will reflect lease expense on a straight-line basis, while finance leases will result in the separate presentation of interest expense on the lease liability (as calculated using the effective interest method) and amortization expense of the right-of-use asset. Quantitative and qualitative disclosures will also be required surrounding significant judgments made by management. The provisions of this pronouncement are effective for calendar year-end, public entities on January 1, 2019 and must be applied on a modified retrospective basis as of the beginning of the earliest comparative period presented. The new standard also provides reporting entities the option to elect a package of practical expedients for existing leases that commenced before the effective date. Early adoption is permitted. The Company is in the process of evaluating the impact to its consolidated financial position, consolidated results of operations, and consolidated cash flows of the adoption of ASU 2016-02.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230), Classification of Certain Cash Receipts and Cash Payments* (ASU 2016-15), with the intention to reduce diversity in practice, as well as simplify elements of classification within the statement of cash flows for certain transactions. The new ASU prescribes specific clarification guidance for the following eight classes of transactions: debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance (COLI) policies, distributions received from equity method investments, beneficial interest in securitization transactions, and separately identifiable cash flows and application of the predominance principal. For calendar year-end public entities, the update will be effective for annual periods beginning January 1, 2018 and requires application using a retrospective transition method. Early adoption is permitted. The Company is in the process of evaluating the impacts of adoption of ASU 2016-15 to the presentation of consolidated cash flows.

Recently Adopted Accounting Standard

In April 2015, the FASB issued ASU 2015-03, *Interest-Imputation of Interest (Subtopic 835-30)* (ASU 2015-03), which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The Company has retrospectively adopted the provisions of ASU 2015-03 as of January 1, 2016, which was the original effective date for calendar year-end, public entities. As a result, unamortized debt expense of $11 million at December 31, 2015 has been reclassified from Other noncurrent assets to a deduction of Long-term debt, net of current portion on the consolidated balance sheets. Unamortized debt expense at December 31, 2016 is also $11 million. Adoption of this guidance had no impact on the Company's consolidated results of operations or consolidated cash flows. In August 2015, the FASB issued ASU 2015-15, *Interest-Imputation of Interest (Subtopic 835-30): Presentation of Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements-Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting (SEC Update)* (ASU 2015-15), which clarifies that the SEC staff would "not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement" given the lack of guidance on this topic in ASU 2015-03. Therefore, as allowed under this update, the Company records debt issuance costs associated with its line-of-credit arrangements as an asset within Other current assets, and amortizes the costs over the term of the agreement.

In May 2015, the FASB issued ASU 2015-07, *Fair Value Measurement (Topic 820), Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), which removes the requirement to categorize within the fair value hierarchy investments for which fair value is measured using the net asset value per share as a practical expedient. The amendments also remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share as a practical expedient. Instead, such disclosures are restricted only to investments that the entity has decided to measure using the practical expedient. The Company has retrospectively adopted the provisions of this update as of January 1, 2016, which was the original effective date for calendar year-end, public entities. As a result, certain investments have been retrospectively reclassified within the Company's fair value disclosures of its Nuclear decommissioning trust and Non-qualified benefit plan trust. See Note 4, Fair Value of Financial Instruments for more information. Also, certain benefit plan assets have been reclassified by the Company as seen in Note 10, Employee Benefits. The adoption of this guidance had no impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

In March 2016, the FASB issued ASU 2016-09, *Compensation-Stock Compensation (Topic 718), Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09), which is designed to simplify the presentation and accounting for certain income tax effects, employer tax withholding requirements, forfeiture assumptions, and statement of cash flows presentation related to share-based payment awards. PGE has early adopted the provisions of this ASU effective January 1, 2016. The main provisions include the following:

- On a prospective basis, all excess tax benefits and deficiencies are recognized within the consolidated statements of income in the year incurred, as opposed to equity, and shall be classified as operating activities in the consolidated statements of cash flows. As a result of adoption, PGE recognized less than $1 million of excess tax benefits related to its share-based payment awards, which was recorded as a reduction of Income tax expense in the consolidated statements of income for the period ended December 31, 2016.
- Reporting entities are now allowed to make a policy election regarding its accounting for forfeitures either by estimating the number of awards that are expected to vest or account for forfeitures when they occur. PGE's stock compensation expense will continue to reflect estimated forfeitures.
- On a retrospective basis, cash paid on behalf of employees related to restricted shares withheld for tax purposes shall now be classified as a financing activity in the statement of cash flows. In the consolidated statements of cash flows for the twelve months ended December 31, 2015 and 2014, PGE has retrospectively reclassified $3 million and $2 million, respectively, from Other non-cash income and expenses, net within operating activities to Other financing outflow activities. For the twelve months ended December 31, 2016, $3 million is reflected as an outflow within the financing activities section.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $6 million as of December 31, 2016 and 2015. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2016	2015	2014
Balance as of beginning of year	$ 6	$ 6	$ 6
Increase in provision	5	6	6
Amounts written off, less recoveries	(5)	(6)	(6)
Balance as of end of year	$ 6	$ 6	$ 6

Trust Accounts

Nuclear decommissioning trust—Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) at the Trojan nuclear power plant (Trojan), which was closed in 1993. The Nuclear decommissioning trust includes amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein. In 2014 and 2013, the Company received $6 million and $44 million, respectively, from the settlement of a legal matter concerning costs associated with the operation of the ISFSI. Those funds were deposited into the Nuclear decommissioning trust. For additional information concerning the legal matter, see Note 7, Asset Retirement Obligations. In anticipation of the refund of the settlement amount to customers over a three-year period that began in 2015, those funds were withdrawn from the Nuclear decommissioning trust during 2015.

Non-qualified benefit plan trust—Reflects assets held in trust to cover the obligations of PGE’s non-qualified benefit plans and represents contributions made by the Company less qualified expenditures plus any realized and unrealized gains and losses on the investment held therein.

The trusts are comprised of the following investments as of December 31 (in millions):

	Nuclear Decommissioning Trust		Non-Qualified Benefit Plan Trust	
	2016	2015	2016	2015
Cash equivalents	$ 21	$ 18	$ 1	$ 1
Marketable securities, at fair value:				
Equity securities	—	—	6	5
Debt securities	20	22	1	1
Insurance contracts, at cash surrender value	—	—	26	26
	$ 41	$ 40	$ 34	$ 33

For information concerning the fair value measurement of those assets recorded at fair value held in the trusts, see Note 4, Fair Value of Financial Instruments.

Other Current Assets and Accrued Expenses and Other Current Liabilities

Other current assets and Accrued expenses and other current liabilities consist of the following (in millions):

	As of December 31,	
	2016	2015
Other current assets:		
Prepaid expenses	$ 48	$ 43
Margin deposits	8	33
Assets from price risk management activities	18	10
Other	3	2
	$ 77	$ 88
Accrued expenses and other current liabilities:		
Regulatory liabilities—current	$ 51	$ 55
Accrued employee compensation and benefits	52	51
Accrued interest payable	25	25
Accrued dividends payable	30	28
Accrued taxes payable	25	25
Other	71	75
	$ 254	$ 259

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company's consolidated balance sheets, for which it is practicable to estimate fair value as of December 31, 2016 and 2015, and then classifies these financial assets and liabilities based on a fair value hierarchy that is used to prioritize the inputs to the valuation techniques used to measure fair value. The three levels and application to the Company are discussed below.

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the measurement date.

Level 2 Pricing inputs include those that are directly or indirectly observable in the marketplace as of the measurement date.

Level 3 Pricing inputs include significant inputs which are unobservable for the asset or liability.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. Pursuant to the adoption of ASU 2015-07, *Fair Value Measurement (Topic 820), Disclosures for Investments in Certain Entities that Calculate Net Asset Value per share (or Its Equivalent),* as disclosed in Note 2, Summary of Significant Accounting Policies, assets measured at fair value using net asset value (NAV) as a practical expedient are not categorized in the fair value hierarchy. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements, and prior period amounts have been retrospectively reclassified to conform to current presentation.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all of its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the years ended December 31, 2016 and 2015, except those presented in this note.

The Company's financial assets and liabilities whose values were recognized at fair value are as follows by level within the fair value hierarchy (in millions):

	As of December 31, 2016				
	Level 1	**Level 2**	**Level 3**	**Other**[(2)]	**Total**
Assets:					
Nuclear decommissioning trust: [(1)]					
Debt securities:					
Domestic government	$ 2	$ 10	$ —	$ —	$ 12
Corporate credit	—	8	—	—	8
Money market funds measured at NAV[(2)]	—	—	—	21	21
Non-qualified benefit plan trust: [(3)]					
Money market funds	1	—	—	—	1
Equity securities—domestic	4	—	—	—	4
Debt securities—domestic government	1	—	—	—	1
Investments measured at NAV:[(2)]					
Money market funds	—	—	—	—	—
Collective trust—domestic equity	—	—	—	2	2
Assets from price risk management activities: [(1)] [(4)]					
Electricity	—	6	1	—	7
Natural gas	—	15	1	—	16
	$ 8	$ 39	$ 2	$ 23	$ 72
Liabilities - Liabilities from price risk management activities: [(1)] [(4)]					
Electricity	$ —	$ 6	$ 112	$ —	$ 118
Natural gas	—	42	9	—	51
	$ —	$ 48	$ 121	$ —	$ 169

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(4) For further information, see Note 5, Price Risk Management.

	As of December 31, 2015				
	Level 1	Level 2	Level 3	Other[2]	Total
Assets:					
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	$ 6	$ 8	$ —	$ —	$ 14
Corporate credit	—	8	—	—	8
Money market funds measured at NAV[2]	—	—	—	18	18
Non-qualified benefit plan trust: [3]					
Money market funds	—	—	—	—	—
Equity securities—domestic	3	—	—	—	3
Debt securities—domestic government	1	—	—	—	1
Investments measured at NAV:[2]					
Money market funds	—	—	—	1	1
Collective trust—domestic equity	—	—	—	2	2
Assets from price risk management activities: [1] [4]					
Electricity	—	7	—	—	7
Natural gas	—	3	—	—	3
	$ 10	$ 26	$ —	$ 21	$ 57
Liabilities - Liabilities from price risk management activities: [1] [4]					
Electricity	$ —	$ 28	$ 105	$ —	$ 133
Natural gas	—	144	14	—	158
	$ —	$ 172	$ 119	$ —	$ 291

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure, and have been retrospectively reclassified pursuant to the implementation of ASU 2015-07. For further information see Note 2, Summary of Significant Accounting Policies.
(3) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(4) For further information, see Note 5, Price Risk Management.

Trust assets held in the Nuclear decommissioning and Non-qualified benefit plan trusts are recorded at fair value in PGE’s consolidated balance sheets and invested in securities that are exposed to interest rate, credit, and market volatility risks. These assets are classified within Level 1, 2, or 3 based on the following factors:

Debt securities—PGE invests in highly-liquid United States treasury securities to support the investment objectives of the trusts. These domestic government securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date.

Assets classified as Level 2 in the fair value hierarchy include domestic government debt securities, such as municipal debt, and corporate credit securities. Prices are determined by evaluating pricing data such as broker quotes for similar securities and adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation as applicable.

Equity securities—Equity mutual fund and common stock securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE).

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value. Redemption is permitted daily without written notice.

For 2015 and most of 2016 money market funds in the NQ Plan were valued at NAV as a practical expedient and not included in the fair value hierarchy. As of December 31, 2016 the NQ Plan transitioned to exchange traded government money market funds and are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices in published exchanges such as NASDAQ and the NYSE. The money market fund in the NDT Plan continues to be valued at NAV as a practical expedient and is not included in the fair value hierarchy.

Common and collective trust funds—PGE invests in common and collective trust funds that invests in equity securities. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value as a practical expedient. A majority of the funds provide for daily liquidity with appropriate written notice. One fund allows for withdrawal from all accounts as of the last day on each calendar month, with at least ten days prior written notice, and provides for a 95% payment to be made within 30 days, and the balance paid after the annual fund audit is complete. Common and collective trusts are not classified in the fair value hierarchy as they are valued at NAV as a practical expedient.

Assets and liabilities from price risk management activities are recorded at fair value in PGE’s consolidated balance sheets and consist of derivative instruments entered into by the Company to manage its exposure to commodity price risk and foreign currency exchange rate risk, and reduce volatility in NVPC for the Company’s retail customers. For additional information regarding these assets and liabilities, see Note 5, Price Risk Management.

For those assets and liabilities from price risk management activities classified as Level 2, fair value is derived using present value formulas that utilize inputs such as forward commodity prices and interest rates. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include commodity forwards, futures, and swaps.

Assets and liabilities from price risk management activities classified as Level 3 consist of instruments for which fair value is derived using one or more significant inputs that are not observable for the entire term of the instrument. These instruments consist of longer term commodity forwards, futures, and swaps.

Quantitative information regarding the significant, unobservable inputs used in the measurement of Level 3 assets and liabilities from price risk management activities is presented below:

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
As of December 31, 2016:							
Electricity physical forward	$ —	$ 112	Discounted cash flow	Electricity forward price (per MWh)	$ 14.25	$ 54.73	$ 38.18
Natural gas financial swaps	1	9	Discounted cash flow	Natural gas forward price (per Dth)	1.85	4.92	2.64
Electricity financial futures	1	—	Discounted cash flow	Electricity forward price (per MWh)	8.57	33.60	25.10
	$ 2	$ 121					
As of December 31, 2015:							
Electricity physical forward	$ —	$ 105	Discounted cash flow	Electricity forward price (per MWh)	$ 8.50	$ 84.47	$ 30.69
Natural gas financial swaps	—	14	Discounted cash flow	Natural gas forward price (per Dth)	2.06	3.70	2.54
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	9.98	27.36	19.26
	$ —	$ 119					

The significant unobservable inputs used in the Company's fair value measurement of price risk management assets and liabilities are long-term forward prices for commodity derivatives. For shorter term contracts, PGE employs the mid-point of the bid-ask spread of the market and these inputs are derived using observed transactions in active markets, as well as historical experience as a participant in those markets. These price inputs are validated against independent market data from multiple sources. For certain long-term contracts, observable, liquid market transactions are not available for the duration of the delivery period. In such instances, the Company uses internally-developed price curves, which derive longer term prices and utilize observable data when available. When not available, regression techniques are used to estimate unobservable future prices. In addition, changes in the fair value measurement of price risk management assets and liabilities are analyzed and reviewed on a quarterly basis by the Company.

The Company's Level 3 assets and liabilities from price risk management activities are sensitive to market price changes in the respective underlying commodities. The significance of the impact is dependent upon the magnitude of the price change and the Company's position as either the buyer or seller of the contract. Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Input	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)

Changes in the fair value of net liabilities from price risk management activities (net of assets from price risk management activities) classified as Level 3 in the fair value hierarchy were as follows (in millions):

	Years Ended December 31,	
	2016	2015
Net liabilities from price risk management activities as of beginning of year	$ 119	$ 100
Net realized and unrealized losses *	11	80
Net transfers in to Level 3 from Level 2	(1)	—
Net transfers out of Level 3 to Level 2	(10)	(61)
Net liabilities from price risk management activities as of end of year	$ 119	$ 119
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 11	$ 80

* Includes nominal net realized losses in 2016 and 2015, respectively.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. During the year ended December 31, 2016, there were $1 million of transfers into Level 3 from Level 2, as reflected in the table above. During 2015, there were no significant amounts transferred into Level 3. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its derivative instruments. Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

Long-term debt is recorded at amortized cost in PGE's consolidated balance sheets. The fair value of the Company's First Mortgage Bonds (FMBs) and Pollution Control Revenue Bonds (PCBs) is classified as a Level 2 fair value measurement and is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. The fair value of PGE's unsecured term bank loans was classified as Level 3 fair value measurement and was estimated based on the terms of the loans and the Company's creditworthiness. The significant unobservable inputs to the Level 3 fair value measurement included the interest rate and the length of the loan. The estimated fair value of the Company's unsecured term bank loans approximated their carrying value.

As of December 31, 2016, the carrying amount of PGE's long-term debt was $2,350 million, net of $11 million of unamortized debt expense, and its estimated aggregate fair value was $2,693 million, consisting of $2,543 million and $150 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy. As of December 31, 2015, the carrying amount of PGE's long-term debt was $2,193 million, net of $11 million of unamortized debt expense, and its estimated aggregate fair value was $2,455 million, classified as Level 2 in the fair value hierarchy.

For fair value information concerning the Company's pension plan assets, see Note 10, Employee Benefits.

NOTE 5: PRICE RISK MANAGEMENT

PGE participates in the wholesale marketplace in order to balance its supply of power, which consists of its own generation combined with wholesale market transactions, to meet the needs of its retail customers, manage risk, and administer its existing long-term wholesale contracts. Such activities include purchases and sales of both power and fuel resulting from economic dispatch decisions for Company-owned generating resources. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, from which changes in prices and/or rates may affect the Company's financial position, results of operations, or cash flow.

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in net variable power costs for its retail customers. Such derivative instruments may include forward, futures, swap, and option contracts, which are recorded at fair value on the consolidated balance sheet, for electricity, natural gas, oil, and foreign currency, with changes in fair value recorded in the consolidated statements of income. In accordance with ratemaking and cost recovery processes authorized by the OPUC, the Company recognizes a regulatory asset or liability to defer the gains and losses from derivative activity until settlement of the associated derivative instrument. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. The Company does not engage in trading activities for non-retail purposes.

PGE's Assets and Liabilities from price risk management activities consist of the following (in millions):

	As of December 31,	
	2016	**2015**
Current assets:		
Commodity contracts:		
Electricity	$ 6	$ 7
Natural gas	12	3
Total current derivative assets	18 (1)	10 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	1	—
Natural gas	4	—
Total noncurrent derivative assets	5 (2)	— (2)
Total derivative assets not designated as hedging instruments	$ 23	$ 10
Total derivative assets	$ 23	$ 10
Current liabilities:		
Commodity contracts:		
Electricity	$ 12	$ 36
Natural gas	32	94
Total current derivative liabilities	44	130
Noncurrent liabilities:		
Commodity contracts:		
Electricity	106	97
Natural gas	19	64
Total noncurrent derivative liabilities	125	161
Total derivative liabilities not designated as hedging instruments	$ 169	$ 291
Total derivative liabilities	$ 169	$ 291

(1) Included in Other current assets on the consolidated balance sheets.
(2) Included in Other noncurrent assets on the consolidated balance sheets.

PGE's net volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions, which are expected to deliver or settle at various dates through 2035, were as follows (in millions):

	As of December 31,					
	2016			2015		
Commodity contracts:						
Electricity		8	MWh		12	MWh
Natural gas		107	Dth		124	Dth
Foreign currency exchange	$	22	Canadian	$	7	Canadian

PGE has elected to report gross on the consolidated balance sheets the positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement. In the case of default on, or termination of, any contract under the master netting arrangements, such agreements provide for the net settlement of all related contractual obligations with a given counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit. As of December 31, 2016 and 2015, gross amounts included as Price risk management liabilities subject to master netting agreements were $115 million and $111 million, respectively, for which PGE posted collateral of $11 million and $14 million, which consisted entirely of letters of credit. As of December 31, 2016, of the gross amounts included, $112 million was for electricity and $3 million was for natural gas compared to $104 million for electricity and $7 million for natural gas recognized as of December 31, 2015.

Net realized and unrealized losses (gains) on derivative transactions not designated as hedging instruments are classified in Purchased power and fuel in the consolidated statements of income and were as follows (in millions):

	Years Ended December 31,					
	2016		2015		2014	
Commodity contracts:						
Electricity	$	34	$	72	$	13
Natural Gas		(56)		103		72
Foreign currency exchange		—		1		—

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the consolidated statements of income by the effects of regulatory accounting. Net (gains) of $13 million and net losses of $160 million and $83 million for the years ended December 31, 2016, 2015, and 2014, respectively, have been offset in Net income.

Assuming no changes in market prices and interest rates, the following table presents the year in which the net unrealized loss recorded as of December 31, 2016 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2017		2018		2019		2020		2021		Thereafter		Total	
Commodity contracts:														
Electricity	$	6	$	7	$	7	$	7	$	7	$	77	$	111
Natural gas		20		7		6		2		—		—		35
Net unrealized loss	$	26	$	14	$	13	$	9	$	7	$	77	$	146

PGE’s secured and unsecured debt is currently rated at investment grade by Moody’s Investors Service (Moody’s) and S&P Global Ratings (S&P). Should Moody’s and/or S&P reduce their rating on the Company’s unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, in the form of cash or letters of credit, based on total portfolio positions with each of those counterparties. Certain other counterparties would have the right to terminate their agreements with the Company.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2016 was $164 million, for which the Company had posted $14 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2016, the cash requirement to either post as collateral or settle the instruments immediately would have been $149 million. As of December 31, 2016, PGE had posted a nominal amount of cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as Margin deposits included in Other current assets on the Company’s consolidated balance sheet.

Counterparties representing 10% or more of Assets and Liabilities from price risk management activities were as follows:

	As of December 31,	
	2016	**2015**
Assets from price risk management activities:		
Counterparty A	22%	5%
Counterparty B	17	8
Counterparty C	12	8
Counterparty D	8	10
Counterparty E	1	59
	60%	90%
Liabilities from price risk management activities:		
Counterparty F	66%	36%
Counterparty C	7%	10%
Counterparty B	5%	10%
	78%	56%

For additional information concerning the determination of fair value for the Company’s Assets and Liabilities from price risk management activities, see Note 4, Fair Value of Financial Instruments.

NOTE 6: REGULATORY ASSETS AND LIABILITIES

The majority of PGE's regulatory assets and liabilities are reflected in customer prices and are amortized over the period in which they are reflected in customer prices. Items not currently reflected in prices are pending before the regulatory body as discussed below.

Regulatory assets and liabilities consist of the following (dollars in millions):

	Weighted Average Remaining Life [1]	As of December 31,			
		2016		2015	
		Current	Noncurrent	Current	Noncurrent
Regulatory assets:					
Price risk management [2]	6 years	$ 26	$ 120	$ 120	$ 161
Pension and other postretirement plans [2]	[3]	—	235	—	239
Deferred income taxes [2]	[4]	—	86	—	86
Debt issuance costs [2]	6 years	—	22	—	16
Other [5]	Various	10	35	9	22
Total regulatory assets		$ 36	$ 498	$ 129	$ 524
Regulatory liabilities:					
Asset retirement removal costs [6]	[4]	$ —	$ 887	$ —	$ 837
Trojan decommissioning activities	3 years	18	—	17	15
Asset retirement obligations [6]	[4]	—	49	—	45
Other	Various	33	22	38	31
Total regulatory liabilities		$ 51 [7]	$ 958	$ 55 [7]	$ 928

(1) As of December 31, 2016.
(2) Does not include a return on investment.
(3) Recovery expected over the average service life of employees.
(4) Recovery expected over the estimated lives of the assets.
(5) Of the total other unamortized regulatory asset balances, a return is recorded on $44 million and $29 million as of December 31, 2016 and 2015, respectively.
(6) Included in rate base for ratemaking purposes.
(7) Included in Accrued expenses and other current liabilities on the consolidated balance sheets.

As of December 31, 2016, PGE had regulatory assets of $44 million earning a return on investment at the following rates: i) $22 million earning a return by inclusion in rate base; ii) $3 million at the approved rate for deferred accounts under amortization, ranging from 1.47% to 2.20%, depending on the year of approval; and iii) $19 million at PGE's 2016 cost of capital of 7.56%.

Price risk management represents the difference between the net unrealized losses recognized on derivative instruments related to price risk management activities and their realization and subsequent recovery in customer prices. For further information regarding assets and liabilities from price risk management activities, see Note 5, Price Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices when recognized in net periodic benefit cost. For further information, see Note 10, Employee Benefits.

Deferred income taxes represents income tax benefits resulting from property-related timing differences that previously flowed to customers and will be included in customer prices when the temporary differences reverse. For further information, see Note 11, Income Taxes.

Debt issuance costs represents unrecognized debt issuance costs related to debt instruments retired prior to the stipulated maturity date.

Asset retirement removal costs represents the costs that do not qualify as AROs and are a component of depreciation expense allowed in customer prices. Such costs are recorded as a regulatory liability as they are collected in prices, and are reduced by actual removal costs incurred.

Trojan decommissioning activities represents proceeds received for the settlement of a legal matter concerning the reimbursement from the United States Department of Energy (USDOE) of certain monitoring costs incurred related to spent nuclear fuel at Trojan, as well as ongoing costs and collections associated with decommissioning activities. The USDOE settlement proceeds will be returned to customers over a three-year period that began January 1, 2015 and offset amounts previously collected from customers in relation to Trojan decommissioning activities.

Asset retirement obligations represents the difference in the timing of recognition of: i) the amounts recognized for depreciation expense of the asset retirement costs and accretion of the ARO; and ii) the amount recovered in customer prices.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2016	2015
Trojan decommissioning activities	$ 44	$ 43
Utility plant	105	97
Non-utility property	12	11
Asset retirement obligations	$ 161	$ 151

Trojan decommissioning activities represents the present value of future decommissioning costs for the plant, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the ISFSI, an interim dry storage facility that is licensed by the Nuclear Regulatory Commission. The ISFSI is to house the spent nuclear fuel at the former plant site until an off-site storage facility is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a USDOE facility is complete, which is not expected prior to 2034.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp, collectively referred to as Plaintiffs) filed a complaint against the USDOE for failure to accept spent nuclear fuel by January 31, 1998. PGE, which holds a 67.5% ownership interest in Trojan, had contracted with the USDOE for the permanent disposal of spent nuclear fuel in order to allow the final decommissioning of Trojan. The Plaintiffs paid for permanent disposal services during the period of plant operation and have met all other conditions precedent. The Plaintiffs sought reimbursement for damages incurred through 2009.

A trial before the U.S. Court of Federal Claims concluded in 2012, with the Court issuing a judgment awarding certain damages to the Plaintiffs. The settlement agreement also provides for a process to submit claims for allowable costs for the periods subsequent to 2009, including an extension to cover costs through 2019. Pursuant to this process, the USDOE agreed to reimburse the Plaintiffs $81 million for costs incurred through 2015 resulting from USDOE delays in accepting spent nuclear fuel. The Plaintiffs have received cumulative cash reimbursements of $79 million and expect to receive $2 million in 2017.

PGE has received proceeds of $50 million related to its share in this legal matter and expects to receive $1 million in 2017. The settlement amounts received were recorded as a regulatory liability to offset amounts previously collected in relation to Trojan decommissioning activities. In December 2014, the OPUC issued an order on the Company's 2015 GRC, authorizing the return of $50 million of the proceeds received related to this legal matter to customers over a three-year period beginning January 1, 2015.

The ARO related to Trojan decommissioning activities was not impacted by the outcome of this legal matter because the proceeds received in connection with the settlement of this legal matter were for past Trojan decommissioning costs and this ARO reflects future Trojan decommissioning costs.

Utility plant represents AROs that have been recognized for the Company's thermal and wind generation sites, distribution and transmission assets, the disposal of which is governed by environmental regulation. During 2016, the Company recorded an overall increase in AROs, including Trojan, of $9 million, with the change comprised of an increase to revisions in estimated cash flows and incurred liabilities of $6 million, accretion of $6 million, and a reduction of $3 million due to settled liabilities.

In 2016, PGE decreased its ARO related to Boardman by $3 million due to changes in the timing of estimated settlement, with corresponding decreases in the cost basis of the plant, included in Electric utility plant, net on the consolidated balance sheet. In 2015, PGE increased its ARO related to Boardman by $9 million, due primarily to changes in timing of estimated settlements and due to the acquisition of additional interests in Boardman. For additional information regarding the Company's interests in Boardman, see Note 16, Jointly-owned Plant.

The United States Environmental Protection Agency (EPA) published a final rule, effective October 19, 2015, that regulates Coal Combustion Residuals (CCRs) under the Resource Conservation and Recovery Act, Subtitle D. The rule imposes extensive new requirements, including location restrictions, design and operating standards, groundwater monitoring and corrective action requirements, and closure and post-closure care requirements on CCR impoundments and landfills that are located on active power plant sites and not closed. The requirements for covered CCR impoundments and landfills under the final rule include commencement or completion of closure activities generally between three and ten years from certain triggering events.

The Boardman coal-fired generating plant (Boardman) produces dry CCRs as a by-product. Disposal of the dry CCRs has historically occurred at an on-site landfill that is permitted and regulated by the State of Oregon under requirements similar to the final EPA rule. PGE has determined that it will continue use of the on-site landfill in compliance with the new rule, and the Company believes the final EPA rule will not have a material effect on operations at Boardman.

In 2016, the Company recorded an increase in the ARO related to Colstrip of $6 million related to updated decommissioning estimates, with a corresponding increase in the cost basis of the plant, included in Electric utility plant, net on the consolidated balance sheet. Colstrip utilizes wet scrubbers and a number of settlement ponds that will require upgrading or closure to meet new regulatory requirements. As a result, in 2015, the Company recorded an increase to the Colstrip AROs in the amount of $17 million. PGE plans to seek recovery in customer prices of the incremental costs associated with the final EPA rule.

In 2016 and 2015, PGE also recorded an increase in AROs totaling $3 million and $4 million, respectively, related to the Company's Beaver natural gas-fired generating plant (Beaver) and Carty.

Non-utility property primarily represents AROs which have been recognized for portions of unregulated properties leased to third parties.

The following is a summary of the changes in the Company's AROs (in millions):

	Years Ended December 31,		
	2016	2015	2014
Balance as of beginning of year	$ 151	$ 116	$ 100
Liabilities incurred	1	2	15
Liabilities settled	(3)	(4)	(3)
Accretion expense	7	7	6
Revisions in estimated cash flows	5	30	(2)
Balance as of end of year	$ 161	$ 151	$ 116

Pursuant to regulation, the amortization of utility plant AROs is included in depreciation expense and in customer prices. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices, approximately $4 million annually, with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the consolidated balance sheet, for funds collected from customers through prices to cover the cost of Trojan decommissioning activities. See "*Trust Accounts*" in Note 3, Balance Sheet Components, for additional information on the Nuclear decommissioning trust.

The Oak Grove hydro facility and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable as management believes that these assets will be used in utility operations for the foreseeable future. Removal costs are charged to accumulated asset retirement removal costs, which is included in Regulatory liabilities on PGE's consolidated balance sheets.

NOTE 8: CREDIT FACILITIES

As of December 31, 2016, PGE had a $500 million revolving credit facility scheduled to expire in November 2019.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. The revolving credit facility contains a provision that allows for two, one-year extensions subject to approval by the banks, requires annual fees based on PGE's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2016, PGE was in compliance with this covenant with a 51.0% debt to total capital ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility.

PGE classifies any borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt in the consolidated balance sheets.

Under the revolving credit facility, as of December 31, 2016, PGE had no borrowings outstanding and there was no commercial paper or letters of credit issued. As a result, as of December 31, 2016, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities that provide a total of $160 million capacity under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, $56 million of letters of credit was outstanding, as of December 31, 2016.

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt in an aggregate amount up to $900 million through February 6, 2018.

Short-term borrowings under these credit facilities and related interest rates were as follows (dollars in millions):

	Years Ended December 31,		
	2016	2015	2014
Average daily amount of short-term debt outstanding	$ 1	$ —	$ —
Weighted daily average interest rate *	0.7%	0.6%	—%
Maximum amount outstanding during the year	$ 23	$ 11	$ —

* Excludes the effect of commitment fees, facility fees and other financing fees.

NOTE 9: LONG-TERM DEBT

Long-term debt consists of the following (in millions):

	As of December 31,	
	2016	2015
First Mortgage Bonds, rates range from 2.51% to 9.31%, with a weighted average rate of 4.86% in 2016 and 5.29% in 2015, due at various dates through 2048	$ 2,090	$ 2,083
Unsecured term bank loans, variable rates of approximately 1.37% due 2017	150	—
Pollution Control Revenue Bonds, 5% rate, due 2033	142	142
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Total long-term debt	2,361	2,204
Less: Unamortized debt expense	(11)	(11)
Less: Current portion of long-term debt	(150)	(133)
Long-term debt, net of current portion	$ 2,200	$ 2,060

First Mortgage Bonds and Unsecured term bank loans—During 2016, PGE issued a total of $140 million of FMBs and repaid long-term debt, in an aggregate amount of $133 million.

In January 2016, the Company issued $140 million of 2.51% Series FMBs due 2021 and repaid $58 million of 3.81% Series FMBs, due in 2017 and $75 million of 5.80% Series FMBs due in 2018. Due to the anticipated repayment of this $133 million in early January 2016, this amount of long-term debt was classified as current on the Company's consolidated balance sheets as of December 31, 2015.

The Indenture securing PGE's outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. Interest is payable semi-annually on FMBs.

In May 2016, PGE entered into an unsecured credit agreement with certain financial institutions, under which the Company had the opportunity to obtain three separate term loans in an aggregate principal amount of up to $200 million by October 31, 2016. Under the agreement, PGE obtained the following term loans:

- $50 million on May 4, 2016;
- $75 million on June 15, 2016; and
- $25 million on October 31, 2016.

The term loan interest rates are set at the beginning of the interest period for periods of 1-month, 3-months, or 6-months, as selected by PGE and are based on the London Interbank Offered Rate (LIBOR) plus 63 basis points, approximately 1.37% as of December 31, 2016, with no other fees.

The credit agreement expires November 30, 2017, at which time any amounts outstanding under the term loans become due and payable. Upon the occurrence of certain events of default, the Company's obligations under the credit agreement may be accelerated. Such events of default include payment defaults to lenders under the credit agreement, covenant defaults and other customary defaults for financings of this type.

Pollution Control Revenue Bonds—The Company has the option to remarket through 2033 the $21 million of PCBs held by PGE as of December 31, 2016. At the time of any remarketing, the Company can choose a new interest rate period that could be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing. The PCBs could be backed by FMBs or a bank letter of credit depending on market conditions. Interest is payable semi-annually on PCBs.

As of December 31, 2016, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2017	$	150
2018		—
2019		300
2020		—
2021		160
Thereafter		1,751
	$	2,361

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan, which has been closed to most new employees since January 31, 2009 and to all new employees since January 1, 2012. No changes were made to the benefits provided to existing participants when the plan was closed to new employees.

The assets of the pension plan are held in a trust and are comprised of equity and debt instruments, all of which are recorded at fair value. Pension plan calculations include several assumptions that are reviewed annually and updated as appropriate, with the measurement date of December 31.

PGE made no contributions to the pension plan in 2016, 2015, and 2014. PGE expects to contribute $3 million to the pension plan in 2017.

In 2014, the Company offered certain eligible participants in the pension plan the option to select a lump sum distribution. As a result of this offering, PGE made lump sum distributions totaling $16 million on July 1, 2014.

Other Postretirement Benefits—PGE has non-contributory postretirement health and life insurance plans, as well as Health Reimbursement Accounts (HRAs) for its employees (collectively, "Other Postretirement Benefits" in the following tables). Employees are covered under a Defined Dollar Medical Benefit Plan, which limits PGE's obligation pursuant to the postretirement health plan by establishing a maximum benefit per employee with employees responsible for the additional cost.

The assets of these plans are held in voluntary employees' beneficiary association trusts and are comprised of money market funds, common stocks, common and collective trust funds, partnerships/joint ventures, and registered investment companies, all of which are recorded at fair value. Postretirement health and life insurance benefit plan calculations include several assumptions that are reviewed annually by PGE and updated as appropriate, with measurement dates of December 31.

Contributions to the HRAs provide for claims by retirees for qualified medical costs. For bargaining employees employed as of April 9, 2004, the participants' accounts are credited with 58% of the value of the employee's accumulated sick time, a stated amount per compensable hour worked, plus 100% of their earned time off accumulated at the time of retirement. For active non-bargaining employees, the Company grants a fixed dollar amount that will become available for qualified medical expenses upon their retirement.

Non-Qualified Benefit Plans—The non-qualified benefit plans (NQBP) in the following tables include obligations for a Supplemental Executive Retirement Plan and a directors pension plan, both of which were closed to new participants in 1997. The NQBP also include pension make-up benefits for employees that participate in the unfunded Management Deferred Compensation Plan (MDCP). Investments in a non-qualified benefit plan trust, consisting of trust-owned life insurance policies and marketable securities, provide funding for the future requirements of these plans. The assets of such trust are included in the accompanying tables for informational purposes only and are not considered segregated and restricted under current accounting standards. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. The measurement date for the non-qualified benefit plans is December 31.

Other NQBP—In addition to the non-qualified benefit plans discussed above, PGE provides certain employees and outside directors with deferred compensation plans, whereby participants may defer a portion of their earned compensation. These unfunded plans include the MDCP and the Outside Directors' Deferred Compensation Plan. PGE holds investments in a non-qualified benefit plan trust that are intended to be a funding source for these plans.

Trust assets and plan liabilities related to the NQBP included in PGE's consolidated balance sheets are as follows as of December 31 (in millions):

	2016			**2015**		
	NQBP	**Other NQBP**	**Total**	**NQBP**	**Other NQBP**	**Total**
Non-qualified benefit plan trust	$ 16	$ 18	$ 34	$ 15	$ 18	$ 33
Non-qualified benefit plan liabilities *	25	80	105	25	81	106

* For the NQBP, excludes the current portion of $2 million in 2016 and 2015, which are classified in Other current liabilities in the consolidated balance sheets.

See "*Trust Accounts*" in Note 3, Balance Sheet Components, for information on the Non-qualified benefit plan trust.

Investment Policy and Asset Allocation—The Board of Directors of PGE appoints an Investment Committee, which is comprised of officers of the Company, and establishes the Company's asset allocation. The Investment Committee is then responsible for implementation and oversight of the asset allocation. The Company's investment policy for its pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities, and other alternative investments. The commitments to each class are controlled by an asset deployment and cash management strategy that takes profits from asset classes whose allocations have shifted above their target ranges to fund benefit payments and investments in asset classes whose allocations have shifted below their target ranges.

The asset allocations for the plans, and the target allocation, are as follows:

	As of December 31,			
	2016		2015	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	68%	67%	67%	67%
Debt securities	32	33	33	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	60%	62%	60%	64%
Debt securities	40	38	40	36
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	15%	11%	15%	14%
Debt securities	7	11	7	8
Insurance contracts	78	78	78	78
Total	100%	100%	100%	100%

* The target for the Defined Benefit Pension Plan represents the mid-point of the investment target range. Due to the nature of the investment vehicles in both the Other Postretirement Benefit Plans and the Non-Qualified Benefit Plans, these targets are the weighted average of the mid-point of the respective investment target ranges approved by the Investment Committee. Due to the method used to calculate the weighted average targets for the Other Postretirement Benefit Plans and Non-Qualified Benefit Plans, reported percentages are affected by the fair market values of the investments within the pools.

The Company's overall investment strategy is to meet the goals and objectives of the individual plans through a wide diversification of asset types, fund strategies, and fund managers. Equity securities primarily include investments across the capitalization ranges and style biases, both domestically and internationally. Fixed income securities include, but are not limited to, corporate bonds of companies from diversified industries, mortgage-backed securities, and U.S. Treasuries. Other types of investments include investments in hedge funds and private equity funds that follow several different strategies.

Pursuant to the adoption of ASU 2015-07, *Fair Value Measurement (Topic 820), Disclosures for Investments in Certain Entities that Calculate Net Asset Value per share (or Its Equivalent)*, as disclosed in Note 2, Summary of Significant Accounting Policies, assets measured at fair value using net asset value (NAV) as a practical expedient are not categorized in the fair value hierarchy. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements. As required by this ASU, prior period amounts have been retrospectively reclassified to conform to current presentation, including all of the investments previously classified as Level 3. As a result, the Level 3 reconciliation is no longer applicable for such investments and has been excluded from this footnote.

The fair values of the Company's pension plan assets and other postretirement benefit plan assets by asset category are as follows (in millions):

	Level 1	Level 2	Level 3	Other *	Total
As of December 31, 2016:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 52	$ —	$ —	$ —	$ 52
Investments measured at NAV:					
Money market funds	—	—	—	6	6
Collective trust funds	—	—	—	483	483
Private equity funds	—	—	—	18	18
	$ 52	$ —	$ —	$ 507	$ 559
Other Postretirement Benefit Plans assets:					
Money market funds	$ 4	$ —	$ —	$ —	$ 4
Equity securities:					
Domestic	—	3	—	—	3
International	8	—	—	—	8
Debt securities—Domestic government	—	4	—	—	4
Investments measured at NAV:					
Money market funds	—	—	—	4	4
Collective trust funds	—	—	—	7	7
	$ 12	$ 7	$ —	$ 11	$ 30
As of December 31, 2015:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 44	$ —	$ —	$ —	$ 44
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	479	479
Private equity funds	—	—	—	22	22
	$ 44	$ —	$ —	$ 506	$ 550
Other Postretirement Benefit Plans assets:					
Money market funds	$ —	$ —	$ —	$ —	$ —
Equity securities:					
Domestic	—	3	—	—	3
International	8	—	—	—	8
Debt securities—Domestic government	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	7	7
Collective trust funds	—	—	—	7	7
	$ 8	$ 8	$ —	$ 14	$ 30

* Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure, and have been retrospectively reclassified pursuant to the implementation of ASU 2015-07. For further information see Note 2, Summary of Significant Accounting Policies.

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 4, Fair Value of Financial Instruments. The following discussion provides information regarding the methods used in valuation of the various asset class investments held in the pension and other postretirement benefit plan trusts.

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, or certificates of deposit. Some of the money market funds held in the trusts are classified as Level 1 instruments as pricing inputs are based on unadjusted prices in an active market. The remaining money market funds are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

Equity securities—Equity mutual fund and common stock securities are classified as Level 1 securities as pricing inputs are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. Mutual fund assets included in separately managed accounts are classified as Level 2 securities due to pricing inputs that are not directly or indirectly observable in the marketplace.

Collective trust funds—Domestic and international mutual fund assets included in commingled trusts or separately managed accounts are valued at NAV as a practical expedient and not included in the fair value hierarchy.

Debt securities, including municipal debt and corporate credit securities, mortgage-backed securities, and asset-backed securities included in commingled trusts are valued at NAV as a practical expedient and not included in the fair value hierarchy.

Private equity funds—PGE invests in a combination of primary and secondary fund-of-funds, which hold ownership positions in privately held companies across the major domestic and international private equity sectors, including but not limited to, partnerships, joint ventures, venture capital, buyout, and special situations. Private equity investments are valued at NAV as a practical expedient.

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and non-qualified benefit plans as of and for the years ended December 31, 2016 and 2015. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2016	2015	2016	2015	2016	2015
Benefit obligation:						
As of January 1	$ 758	$ 777	$ 81	$ 83	$ 27	$ 27
Service cost	16	18	2	2	—	—
Interest cost	33	31	4	3	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial (gain) loss	26	(31)	(11)	(4)	1	1
Contractual termination benefits	—	—	—	1	—	—
Benefit payments	(34)	(35)	(5)	(6)	(2)	(2)
Administrative expenses	(2)	(2)	—	—	—	—
As of December 31	$ 797	$ 758	$ 73	$ 81	$ 27	$ 27
Fair value of plan assets:						
As of January 1	$ 550	$ 591	$ 30	$ 32	$ 15	$ 15
Actual return on plan assets	45	(4)	1	(2)	1	—
Company contributions	—	—	2	4	2	2
Participants' contributions	—	—	2	2	—	—
Benefit payments	(34)	(35)	(5)	(6)	(2)	(2)
Administrative expenses	(2)	(2)	—	—	—	—
As of December 31	$ 559	$ 550	$ 30	$ 30	$ 16	$ 15
Unfunded position as of December 31	$ (238)	$ (208)	$ (43)	$ (51)	$ (11)	$ (12)
Accumulated benefit plan obligation as of December 31	$ 714	$ 681	N/A	N/A	$ 27	$ 27
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 16	$ 15
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(238)	(208)	(43)	(51)	(25)	(25)
Net liability	$ (238)	$ (208)	$ (43)	$ (51)	$ (11)	$ (12)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ 21	$ 13	$ (10)	$ —	$ 1	$ 1
Amortization of net actuarial loss	(14)	(20)	—	(1)	(1)	(1)
Amortization of prior service cost	—	—	(1)	(1)	—	—
	$ 7	$ (7)	$ (11)	$ (2)	$ —	$ —
Amounts included in AOCL*:						
Net actuarial loss (gain)	$ 236	$ 228	$ (2)	$ 9	$ 13	$ 13
Prior service cost	—	—	1	1	—	—
	$ 236	$ 228	$ (1)	$ 10	$ 13	$ 13

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2016	2015	2016	2015	2016	2015
Assumptions used:						
Discount rate for benefit obligation	4.17%	4.36%	3.75% - 4.23%	3.90% - 4.45%	4.17%	4.36%
Discount rate for benefit cost	4.36%	4.02%	3.90% - 4.45%	3.07% - 4.10%	4.36%	4.02%
Weighted average rate of compensation increase for benefit obligation	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Weighted average rate of compensation increase for benefit cost	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets for benefit obligation	7.50%	7.50%	6.26%	6.29%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	7.50%	7.50%	6.29%	6.37%	N/A	N/A

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Regulatory assets due to the future recoverability from retail customers. Accordingly, as of the balance sheet date, such amounts are included in Regulatory assets.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2016	2015	2014	2016	2015	2014	2016	2015	2014
Service cost	$ 16	$ 18	$ 15	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	33	31	34	4	3	4	1	1	1
Expected return on plan assets	(40)	(40)	(39)	(2)	(2)	(2)	—	—	—
Amortization of prior service cost	—	—	—	1	1	1	—	—	—
Amortization of net actuarial loss	14	20	17	—	1	1	1	1	1
Net periodic benefit cost	$ 23	$ 29	$ 27	$ 5	$ 5	$ 6	$ 2	$ 2	$ 2

PGE estimates that $15 million will be amortized from AOCL into net periodic benefit cost in 2017, consisting of a net actuarial loss of $13 million for pension benefits, $1 million for non-qualified benefits, and $1 million for prior service costs for other postretirement benefits. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

The following table summarizes the benefits expected to be paid to participants in each of the next five years and in the aggregate for the five years thereafter (in millions):

	Payments Due					
	2017	2018	2019	2020	2021	2022 - 2026
Defined benefit pension plan	$ 37	$ 39	$ 40	$ 42	$ 43	$ 229
Other postretirement benefits	5	5	5	4	5	22
Non-qualified benefit plans	3	2	3	2	2	10
Total	$ 45	$ 46	$ 48	$ 48	$ 50	$ 261

All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns, with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth. Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

For measurement purposes, the assumed health care cost trend rates, which can affect amounts reported for the health care plans, were as follows:

- For 2016, 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017, decreasing to 6.5% in 2018, then decreasing 0.25% per year thereafter, reaching 5% in 2023;
- For 2015, 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2016, decreasing to 6.0% in 2017, then decreasing 0.25% per year thereafter, reaching 5% in 2021; and
- For 2014, 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2015, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019.

A one percentage point increase or decrease in the above health care cost assumption would have no material impact on total service or interest cost, or on the postretirement benefit obligation.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan that covers substantially all employees. For eligible employees who are covered by PGE’s defined benefit pension plan, the Company matches employee contributions up to 6% of the employee’s base pay. For eligible employees who are not covered by PGE’s defined benefit pension plan, the Company contributes 5% of the employee’s base salary, whether or not the employee contributes to the 401(k) Plan, and also matches employee contributions up to 5% of the employee’s base pay.

For the majority of bargaining employees who are subject to the International Brotherhood of Electrical Workers Local 125 agreements the Company contributes an additional 1% of the employee’s base salary, whether or not the employee contributes to the 401(k) Plan.

All contributions are invested in accordance with employees’ elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $19 million in 2016, $17 million in 2015, and $16 million in 2014.

NOTE 11: INCOME TAXES

Income tax expense consists of the following (in millions):

	Years Ended December 31,		
	2016	2015	2014
Current:			
Federal	$ 10	$ 4	$ 20
State and local	3	1	2
	13	5	22
Deferred:			
Federal	23	26	26
State and local	14	14	13
	37	40	39
Income tax expense	$ 50	$ 45	$ 61

The significant differences between the U.S. federal statutory rate and PGE’s effective tax rate for financial reporting purposes are as follows:

	Years Ended December 31,		
	2016	2015	2014
Federal statutory tax rate	35.0 %	35.0 %	35.0 %
Federal tax credits *	(18.2)	(19.0)	(11.4)
State and local taxes, net of federal tax benefit	4.8	4.2	3.9
Flow through depreciation and cost basis differences	0.2	—	(2.3)
Other	(1.2)	0.5	0.8
Effective tax rate	20.6 %	20.7 %	26.0 %

* Federal tax credits consist primarily of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities. The federal PTCs are earned based on a per-kilowatt hour rate, and as a result, the annual amount of PTCs earned will vary based on weather conditions. The PTCs are generated for 10 years from the corresponding facility’s in service date. PGE’s PTCs end at various dates between 2017 and 2024.

Deferred income tax assets and liabilities consist of the following (in millions):

	As of December 31, 2016	As of December 31, 2015
Deferred income tax assets:		
Employee benefits	$ 181	$ 170
Price risk management	59	112
Regulatory liabilities	29	42
Tax credits	56	46
Other	5	—
Total deferred income tax assets	330	370
Deferred income tax liabilities:		
Depreciation and amortization	829	781
Regulatory assets	170	220
Other	—	1
Total deferred income tax liabilities	999	1,002
Deferred income tax liability, net	$ (669)	$ (632)

As of December 31, 2016, PGE has federal credit carryforwards of $56 million, which will expire at various dates through 2036.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2016 and 2015 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2016 and 2015, PGE had no unrecognized tax benefits.

PGE and its subsidiaries file a consolidated federal income tax return. The Company also files income tax returns in the states of Oregon, California, and Montana, and in certain local jurisdictions. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2010 and all issues were resolved related to those years. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the consolidated financial statements.

NOTE 12: EQUITY-BASED PLANS

Equity Forward Sale Agreement

PGE entered into an equity forward sale agreement (EFSA) in connection with a public offering of 11,100,000 shares of its common stock in June 2013. In 2013, the Company issued 700,000 shares of its common stock pursuant to the EFSA for net proceeds of $20 million. During the second quarter 2015, PGE physically settled in full the EFSA by issuing 10,400,000 shares of common PGE common stock in exchange for cash of $271 million.

Prior to settlement, the potentially issuable shares pursuant to the EFSA were reflected in PGE's diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of PGE's common stock used in calculating diluted earnings per share for a reporting period were increased by the number of shares, if any, that would be issued upon physical settlement of the EFSA less the number of shares that could have been purchased by PGE in the market with the proceeds received from issuance (based on the average market price during that reporting period).

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock (based on fair value on the purchase date) or 1,500 shares, whichever is less. Two, six-month offering periods occur annually, January 1 through June 30 and July 1 through December 31, during which eligible employees may purchase shares of PGE common stock at a price equal to 95% of the fair value of the stock on the purchase date, the last day of the offering period. As of December 31, 2016, there were 369,419 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

PGE has a Dividend Reinvestment and Direct Stock Purchase Plan (DRIP), under which a total of 2,500,000 shares of the Company's common stock may be issued. Under the DRIP, investors may elect to buy shares of the Company's common stock or elect to reinvest cash dividends in additional shares of the Company's common stock. As of December 31, 2016, there were 2,474,164 shares available for future issuance pursuant to the DRIP.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company 2006 Stock Incentive Plan (the Plan), the Company may grant a variety of equity-based awards, including restricted stock units (RSUs) with time-based vesting conditions (time-based RSUs) and performance-based vesting conditions (performance-based RSUs), to non-employee directors, officers, and certain key employees. Service requirements generally must be met for RSUs to vest. For each grant, the number of RSUs is determined by dividing the specified award amount for each grantee by the closing stock price on the date of grant. RSU activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2013	431,090	$ 26.31
Granted	203,410	31.49
Forfeited	(12,278)	29.90
Vested	(158,329)	24.95

Outstanding as of December 31, 2014	463,893	28.96
Granted	181,797	34.77
Forfeited	(14,988)	34.10
Vested	(187,709)	25.82
Outstanding as of December 31, 2015	442,993	32.84
Granted	193,734	35.89
Forfeited	(3,044)	28.62
Vested	(174,891)	31.47
Outstanding as of December 31, 2016	458,792	34.68

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 3,305,920 shares remain available for future issuance as of December 31, 2016.

Outstanding RSUs provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. DERs represent an amount equal to dividends paid to shareholders on a share of PGE's common stock and vest on the same schedule as the RSUs. The DERs are settled in cash (for grants to non-employee directors) or shares of PGE common stock valued either at the closing stock price on the vesting date (for performance-based RSUs) or dividend payment date (for all other grants). The cash from the settlement of the DERs for non-employee directors may be deferred under the terms of the Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan.

Time-based RSUs vest in either equal installments over a one-year period on the last day of each calendar quarter, over a three-year period on each anniversary of the grant date, or at the end of a three-year period following the grant date. The fair value of time-based RSUs is measured based on the closing price of PGE common stock on the date of grant and charged to compensation expense on a straight-line basis over the requisite service period for the entire award. The total value of time-based RSUs vested was less than $1 million for the years ended December 31, 2016, 2015, and 2014.

Performance-based RSUs vest if performance goals are met at the end of a three-year performance period. Grants are based on three equally-weighted metrics: i) return on equity relative to allowed return on equity; ii) regulated asset base growth; and iii) a relative total shareholder return (TSR) of PGE's common stock as compared to the Edison Electric Institute Regulated Index (EEI Index) during the performance period. Vesting of performance-based RSUs is calculated by multiplying the number of units granted by a performance percentage determined by the Compensation and Human Resources Committee of PGE's Board of Directors. The performance percentage is calculated based on the extent to which the performance goals are met. In accordance with the Plan, however, the committee may disregard or offset the effect of extraordinary, unusual or non-recurring items in determining results relative to these goals. Based on the attainment of the performance goals, the awards can range from zero to 150% of the grant.

For the return on equity and regulated asset base growth portions of the performance-based RSUs, fair value is measured based on the closing price of PGE common stock on the date of grant. For the TSR portion of the performance-based RSUs, fair value is determined using a Monte Carlo simulation model utilizing actual information for the common shares of PGE and its peer group for the period from the beginning of the performance period to the grant date and estimated future stock volatility over the remaining performance period. The fair value of stock-based compensation related to the TSR component of performance-based RSUs was determined using the Monte Carlo model and the following weighted average assumptions:

	2016	2015
Risk-free interest rate	0.9%	1.0%
Expected dividend yield	—%	—%
Expected term (in years)	3.0	3.0
Volatility	14.5% - 25.9%	13.2% - 19.2%

The fair value of performance-based RSUs is charged to compensation expense on a straight-line basis over the requisite service period for the entire award based on the number of shares expected to vest. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the weighted average vesting of 121.2%, 117.3%, and 111.2% of awarded performance-based RSUs for the respective 2016, 2015, and 2014 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $5 million for the year ended December 31, 2016, $4 million for 2015, and $3 million for 2014.

Stock-based compensation, included in Administrative and other expense in the consolidated statements of income, was $6 million for the years ended December 31, 2016, 2015, and 2014. Such amounts differ from those reported in the consolidated statements of equity for Stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. Not included in Administrative and other expenses in the consolidated statements of income, is the net impact from these income tax payments, partially offset by the issuance of DERs, resulting in a charge to equity of $2 million in 2016 and 2015, and $1 million in 2014.

As of December 31, 2016, unrecognized stock-based compensation expense was $6 million, of which approximately $4 million and $2 million is expected to be expensed in 2017 and 2018, respectively. No stock-based compensation costs have been capitalized and the Plan had no material impact on cash flows for the years ended December 31, 2016, 2015, or 2014.

NOTE 14: EARNINGS PER SHARE

Basic earnings per share is computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share is computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Potential common shares consist of: i) employee stock purchase plan shares; ii) contingently issuable time-based and performance-based restricted stock units, along with associated dividend equivalent rights; and iii) shares issuable pursuant to the EFSA. During the second quarter of 2015, PGE physically settled in full the EFSA, with the issuance of 10,400,000 shares of common stock. Prior to settlement, the potentially issuable shares pursuant to the EFSA were reflected in PGE's diluted earnings per share calculations using the treasury stock method. See Note 12, Equity-based Plans, for additional information on the EFSA and its impact on earnings per share.

Net income attributable to PGE common shareholders is the same for both the basic and diluted earnings per share computation. The reconciliations of the denominators of the basic and diluted earnings per share computations are as follows (in thousands):

	Years Ended December 31,		
	2016	2015	2014
Weighted average common shares outstanding—basic	88,896	84,180	78,180
Dilutive effect of potential common shares	158	161	2,314
Weighted average common shares outstanding—diluted	89,054	84,341	80,494

NOTE 15: COMMITMENTS AND GUARANTEES

Purchase Commitments

As of December 31, 2016, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2017	2018	2019	2020	2021	Thereafter	Total
Capital and other purchase commitments	$ 176	$ 8	$ 2	$ 9	$ 1	$ 60	$ 256
Purchased power and fuel:							
Electricity purchases	221	157	181	256	239	1,750	2,804
Capacity contracts	7	6	5	4	4	12	38
Public utility districts	4	4	1	—	1	11	21
Natural gas	53	39	32	27	24	158	333
Coal and transportation	17	9	5	—	—	—	31
Total	$ 478	$ 223	$ 226	$ 296	$ 269	$ 1,991	$ 3,483

Capital and other purchase commitments—Certain commitments have been made for 2017 and beyond that include those related to hydro licenses, upgrades to generation, distribution, and transmission facilities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase agreements with counterparties, which expire at varying dates through 2049, and power capacity contracts through 2024.

Public utility districts—PGE has long-term power purchase agreements with certain public utility districts in the state of Washington and with the City of Portland, Oregon. Under the agreements, the Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether or not they are operable. The future minimum payments for the public utility districts in the preceding table reflect the principal payment only and do not include interest, operation, or maintenance expenses.

Selected information regarding these projects is summarized as follows (dollars in millions):

	Revenue Bonds as of December 31, 2016	PGE's Share as of December 31, 2016		Contract Expiration	PGE Cost, including Debt Service		
		Output	Capacity		2016	2015	2014
			(in MW)				
Priest Rapids and Wanapum	$ 1,190	8.6%	163	2052	$ 16	$ 18	$ 14
Wells	177	19.4	150	2018	10	10	10
Portland Hydro	—	100.0	36	2017	1	2	4

The agreements for Priest Rapids, Wanapum, and Wells provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of the output and operating and debt service costs of the defaulting purchaser. For Wells, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any of the public utility district's outstanding debt for the portion of the project that benefits tax exempt purchasers.

Natural gas—PGE has contracts for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company also has a natural gas storage agreement for the purpose of fueling the Company's Port Westward Unit 1 (PW1), PW2, and Beaver natural gas-fired generating plants.

Coal and transportation—PGE has coal and related rail transportation agreements with take-or-pay provisions related to Boardman that expire at various dates through 2020.

Lease Obligations

As of December 31, 2016, PGE's estimated future minimum lease payments pursuant to capital, build-to-suit, and operating leases for the following five years and thereafter are as follows (in millions):

	Future Minimum Lease Payments		
	Capital Leases	Build-to-Suit	Operating Leases
2017	$ 7	$ —	$ 10
2018	7	4	9
2019	6	14	6
2020	6	13	6
2021	6	13	7
Thereafter	77	237	177
Total minimum lease payments	$ 109	$ 281	$ 215
Less imputed interest	55		
Present value of net minimum lease payments	$ 54		
Less current portion	3		
Non-current portion	$ 51		

Capital Leases—PGE has entered into agreements to purchase natural gas transportation capacity to serve Carty via a 24-mile natural gas pipeline, Carty Lateral, that was constructed to serve the Carty facility. The Company has entered into a 30-year agreement to purchase the entire capacity of Carty Lateral, which is approximately 175,000 decatherms per day. At the end of the initial contract term, the Company has the option to renew the agreement in continuous three-year increments with at least 24-months prior written notice.

As of December 31, 2016, a capital lease asset of $57 million was reflected within Electric utility plant and accumulated amortization of such assets of $3 million was reflected within Accumulated depreciation and amortization in the table above. The present value of the future minimum lease payments due under the agreement included $3 million within Accrued expenses and other current liabilities and $51 million in Other noncurrent liabilities on the consolidated balance sheets. For ratemaking purposes capital leases are treated as operating leases; therefore, in accordance with the accounting rules for regulated operations, the amortization of the leased asset is based on the rental payments recovered from customers. Also for ratemaking purposes, such rental payments were capitalized to the Carty project prior to its in service date of July 29, 2016 and, as a result, amortization of the leased asset of $2 million and interest expense of $3 million was capitalized to CWIP. Beginning August 1, 2016, amortization of the leased asset of $1 million and interest expense of $2 million has been recorded to Purchased power and fuel expense in the consolidated statements of income through December 31, 2016.

Build-to-suit—PGE has entered into a 30-year lease agreement with a local natural gas company, NW Natural, to expand their current natural gas storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-mile pipeline, which will be designed to provide no-notice storage and transportation services to PGE's PW1, PW2, and Beaver natural gas-fired generating plants. Pursuant to the agreement, on September 30, 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which the gas company estimates will be completed during the winter of 2018-2019, at a cost of approximately $128 million. Due to the level of PGE's involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE has recorded $21 million to CWIP and a corresponding liability for the same amount to Other noncurrent liabilities in the consolidated balance sheets as of December 31, 2016. Upon completion of the facility, PGE will assess whether the assets and liabilities qualify as a successful sale-leaseback transaction in which the asset and liability are removed and accounted for as either a capital or operating lease. The table above reflects PGE's estimated future minimum lease payments pursuant to the agreement based on estimated costs and assumes three 10-year renewable options are exercised.

Operating leases—PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities that expire in various years, including the Port of St. Helens land lease, which expires in 2096 and covers the location of PW1, PW2, and Beaver. Rent expense was $10 million in 2016 and 2015, and $11 million in 2014.

The future minimum operating lease payments presented is net of sublease income of $4 million in each of 2017, 2018, 2019, and 2020; and $3 million in 2021. Sublease income was $4 million in 2016, and $3 million in 2015 and 2014.

Guarantees

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2016, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the consolidated balance sheets with respect to these indemnities.

NOTE 16: JOINTLY-OWNED PLANT

As of December 31, 2016, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation*	Construction Work In Progress
Boardman	90.00%	1980	$ 514	$ 400	$ —
Colstrip	20.00	1986	528	342	9
Pelton/Round Butte	66.67	1958 / 1964	255	63	5
Total			$ 1,297	$ 805	$ 14

* Excludes AROs and accumulated asset retirement removal costs.

Under the respective joint operating agreements for the three generating facilities, each participating owner is responsible for financing its share of construction, operating, and leasing costs. PGE's proportionate share of direct operating and maintenance expenses of the facilities is included in the corresponding operating and maintenance expense categories in the consolidated statements of income.

NOTE 17: CONTINGENCIES

PGE is subject to legal, regulatory, and environmental proceedings, investigations, and claims that arise from time to time in the ordinary course of its business. Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. The Company may seek regulatory recovery of certain costs that are incurred in connection with such matters, although there can be no assurance that such recovery would be granted.

Loss contingencies are accrued, and disclosed if material, when it is probable that an asset has been impaired or a liability incurred as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be reasonably estimated, then the Company i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate, or ii) discloses that an estimate cannot be made and the reasons.

If an asset has been impaired or a liability incurred after the financial statement date, but prior to the issuance of the financial statements, the loss contingency is disclosed, if material, and the amount of any estimated loss is recorded in the subsequent reporting period.

The Company evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which: i) the damages sought are indeterminate or the basis for the damages claimed is not clear; ii) the proceedings are in the early stages; iii) discovery is not complete; iv) the matters involve novel or unsettled legal theories; v) there are significant facts in dispute; vi) there are a large number of parties (including circumstances in which it is uncertain how liability, if any, will be shared among multiple defendants); or vii) there is a wide range of potential outcomes. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

Carty

Construction Litigation—In 2013, the Company entered into an agreement (Construction Agreement) with its engineering, procurement and construction contractor - Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership, an affiliate of Abengoa S.A. (collectively, the “Contractor”) - for the construction of Carty, a baseload natural gas-fired generating plant in Eastern Oregon, located adjacent to Boardman. Liberty Mutual Insurance Company and Zurich American Insurance Company (hereinafter referred to collectively as the “Sureties”) provided a performance bond of $145.6 million (Performance Bond) under the Construction Agreement.

On December 18, 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Following termination of the Construction Agreement, PGE, in consultation with the Sureties, brought on new contractors and construction resumed during the week of December 21, 2015.

On January 28, 2016, the Company received notice from the International Chamber of Commerce (ICC) International Court of Arbitration that Abengoa S.A. had submitted a request for arbitration. In the request, Abengoa S.A. alleged that the Company’s termination of the Construction Agreement was wrongful and in breach of the agreement terms and does not give rise to any liability of Abengoa S.A. under the terms of a guaranty in favor of PGE and pursuant to which Abengoa S.A. agreed to guaranty certain obligations of the Contractor under the Construction Agreement. PGE disagrees with the assertions in the request for arbitration and on February 29, 2016 filed a complaint and motion for preliminary injunction in the U.S. District Court for the District of Oregon seeking to have the arbitration claim dismissed on the grounds that the Company has not made a demand under the Abengoa S.A. guaranty, and therefore the matter is not ripe for arbitration.

On March 28, 2016, Abengoa S.A. and several of its foreign affiliates filed petitions for recognition under Chapter 15 of the U.S. Bankruptcy Code requesting interim relief, including an injunction precluding the prosecution of any proceedings against the Chapter 15 debtors. On March 29, 2016, a number of Abengoa S.A.’s U.S. subsidiaries, including the four entities that collectively comprise the Contractor, filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. As a result, on April 5, 2016, the U.S. District Court issued an order stating that the Company’s District Court action against Abengoa S.A. was stayed. In early October 2016, the bankruptcy court in the Chapter 11 proceeding granted the Company’s motion for relief from stay with respect to the four entities that collectively comprise the Contractor, which allows the Company to bring claims against such entities in the U.S. District Court. On October 21, 2016, PGE filed a complaint in the U.S. District Court for the District of Oregon against Abeinsa for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from Abeinsa in excess of $200 million for: i) costs incurred to complete construction of Carty, settle claims with unpaid contractors and vendors and remove liens; and ii) damages in excess of the construction costs, including a project management fee, liquidated damages under the Construction Agreement, legal fees and costs, damages due to delay of the project, warranty costs, and interest.

On March 9, 2016, the Sureties delivered a letter to the Company denying liability in whole under the Performance Bond. In the letter, the Sureties make the following assertions in support of their determination:

1. that, because Abengoa S.A. has alleged that PGE wrongfully terminated the Construction Agreement, PGE must disprove such claim as a condition precedent to recovery under the Performance Bond; and
2. that, irrespective of the outcome of the foregoing wrongful termination claim, the Sureties have various contractual and equitable defenses to payment and are not liable to PGE for any amount under the Performance Bond.

The Company disagrees with the foregoing assertions and, on March 23, 2016, filed a breach of contract action against the Sureties in the U.S. District Court for the District of Oregon. The Company's complaint disputes the Sureties' assertion that the Company wrongfully terminated the Construction Agreement and asserts that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Sureties' breach of contract, including damages in excess of the $145.6 million stated amount of the Performance Bond. Such damages include additional costs incurred by PGE to complete Carty.

On April 15, 2016, the Sureties filed a motion to stay this U.S. District Court proceeding, alleging that PGE's claims should be addressed in the arbitration proceeding initiated by Abengoa S.A. and referenced above because PGE's claims are intertwined with the issues involved in such arbitration and all parties necessary to resolve PGE's claims are parties to the arbitration. PGE opposed the motion and filed a motion to enjoin the Sureties from pursuing, in the ICC arbitration proceeding, claims relating to the Performance Bond. On July 27, 2016, the court denied the Sureties' motion to stay and granted PGE's motion for a preliminary injunction. The Sureties appealed the rulings to the Ninth Circuit Court of Appeals. On December 13, 2016, the Ninth Circuit issued an Order staying the district court proceeding, pending a decision on the Sureties' appeal. Oral argument on the Sureties' appeal is scheduled for May 2017.

Recovery of Capital Costs in Excess of $514 million—Following termination of the Construction Agreement, PGE brought on new contractors and resumed construction. Carty was placed into service on July 29, 2016 and the Company began including its revenue requirement, based on the approved cost of $514 million, in customer prices on August 1. Costs for Carty have exceeded the $514 million approved for inclusion in customer prices by the OPUC. The incremental costs resulted from various matters relating to the resumption of construction activities following the termination of the Construction Agreement, including, among other things, determining the remaining scope of construction, preparing work plans for contractors, identifying new contractors, negotiating contracts, and procuring additional materials. Costs also increased as a result of PGE's discovery through the construction process of latent defects in work performed by the former Contractor and the corresponding labor and materials required to correct the work. Other items contributing to the increase include costs relating to the removal of certain liens filed on the property for goods and services provided under contracts with the former Contractor, and costs to repair equipment damage resulting from poor storage and maintenance on the part of the former Contractor.

As of December 31, 2016, PGE has capitalized $634 million for Carty classified as Electric utility plant. PGE currently estimates the total cost of Carty will be approximately $640 million. This cost estimate does not reflect any offsetting amounts that may be received from the Sureties pursuant to the Performance Bond. This estimate also excludes approximately $17 million of lien claims filed against PGE for goods and services provided under contracts with the former Contractor. The Company believes these liens are invalid and is contesting the claims in the courts.

In the event the total project costs incurred by PGE, net of offsetting amounts that may be received from the Sureties, Abengoa S.A., or the Contractor, exceed the $514 million amount approved by the OPUC for inclusion in customer prices, the Company intends to seek approval to recover the excess amounts in customer prices in a subsequent rate proceeding after exhausting all remedies against the aforementioned parties. However, there is no assurance that such recovery would be allowed by the OPUC. In accordance with GAAP and the Company's accounting policies, any such excess costs would be charged to expense at the time disallowance of recovery becomes probable and a reasonable estimate of the amount of such disallowance can be made. As of the date of this report, the Company has concluded that the likelihood that a portion of the cost of Carty will be disallowed for recovery in customer prices is less than probable. Accordingly, no loss has been recorded to date related to the project.

As actual project costs for Carty exceed $514 million, the Company is incurring a higher cost than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation and interest expense. On July 29, 2016, the Company requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the incremental capital costs for Carty starting from its in service date to the date that such amounts are approved in a subsequent GRC proceeding. The Company has requested that the OPUC delay its review of this deferral request until the Company's claims against the Sureties have been resolved. Until such time, the effects of this higher cost are recognized in the Company's results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP. Any amounts approved by the OPUC for recovery under the deferral filing will be recognized in earnings in the period of such approval, however there is no assurance that such recovery would be granted by the OPUC. The Company believes that costs incurred to date and capitalized in Electric utility plant, net in the consolidated balance sheet were prudently incurred. There have been no settlement discussions with regulators related to such costs.

EPA Investigation of Portland Harbor

A 1997 investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) as a federal Superfund site and listed 69 Potentially Responsible Parties (PRPs). PGE was included among the PRPs as it has historically owned or operated property near the river. In 2008, the EPA requested information from various parties, including PGE, concerning additional properties in or near the original segment of the river under investigation as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

The Portland Harbor site remedial investigation (RI) has been completed pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs known as the Lower Willamette Group (LWG), which does not include PGE. The LWG has funded the RI and feasibility study (FS) and has stated that it has incurred $115 million in investigation-related costs. The Company anticipates that such costs will ultimately be allocated to PRPs as a part of the allocation process for remediation costs of the EPA's preferred remedy.

The EPA has finalized the FS, along with the RI, and these documents provided the framework for the EPA to determine a clean-up remedy for Portland Harbor that was documented in a Record of Decision (ROD) issued on January 6, 2017. The ROD outlines the EPA's selected remediation alternative to clean-up for Portland Harbor which has an estimated total cost of $1.7 billion, comprised of $1.2 billion related to remediation construction costs and $0.5 billion related to long-term operation and maintenance costs, for a combined discounted present value of $1.05 billion. Remediation construction costs are estimated to be incurred over a 13 year period, with long-term operation and maintenance costs estimated to be incurred over a 30 year period from the start of construction. The Company anticipates that prior to the commencement of remediation activities, a phase of resampling of the river will be necessary to better refine the remedial design and may impact estimated costs.

PGE is participating in a voluntary process to determine an appropriate allocation of costs amongst the PRPs. Significant uncertainties remain surrounding facts and circumstances that are integral to the determination of such an allocation percentage, including a final allocation methodology and data with regard to property specific activities and history of ownership of sites within Portland Harbor. Based on the above facts and remaining uncertainties, PGE cannot reasonably estimate its potential liability or determine an allocation percentage that represents PGE's portion of the liability to clean-up Portland Harbor.

Where injuries to natural resources have occurred as a result of releases of hazardous substances, federal and state natural resource trustees may seek to recover for damages at such sites, which are referred to as natural resource damages. As it relates to the Portland Harbor, PGE has been participating in the Portland Harbor Natural Resource Damages assessment (NRDA) process. The EPA does not manage NRDA activities, but provides claims information and coordination support to the Natural Resource Damages (NRD) trustees. Damage assessment activities are typically conducted by a Trustee Council made up of the trustee entities for the site, and claims are not concluded until a final remedy for clean-up has been settled. The Portland Harbor NRD trustees are the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the State of Oregon, and certain tribal entities.

After the claimed damages at a site are assessed, the NRD trustees may seek to negotiate legal settlements or take other legal actions against the parties responsible for the damages. Funds from such settlements must be used to restore injured resources and may also compensate the trustees for costs incurred in assessing the damages. The NRD trustees are in the process of assigning initial NRDA liability allocations to PRPs, which the Company anticipates will occur throughout the first half of 2017. PGE believes that the Company's portion of NRDA liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

As discussed above, significant uncertainties still remain concerning the precise boundaries for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, the amount of natural resource damages, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. However, the Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of the Portland Harbor site, although such costs could be material. The Company plans to seek recovery of any costs resulting from the Portland Harbor proceeding through claims under insurance policies and regulatory recovery in customer prices.

On July 15, 2016, the Company filed a deferral application with the OPUC to allow for the deferral of the future environmental remediation costs, as well as, seek authorization to establish a regulatory cost recovery mechanism for such environmental costs. The Company has reached an agreement with OPUC Staff and other parties regarding the details of the recovery mechanism, subject to OPUC final decision, which is expected in the first quarter of 2017. The mechanism, as proposed, would allow the Company to recover incurred environmental expenditures through a combination of third-party proceeds, such as insurance recoveries, and through customer prices, as necessary. The mechanism would establish annual prudency reviews of environmental expenditures and be subject to an annual earnings test.

Trojan Investment Recovery Class Actions

In 1993, PGE closed the Trojan nuclear power plant (Trojan) and sought full recovery of, and a rate of return on, its Trojan costs in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order that granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan.

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the matter to the OPUC for reconsideration.

In 2008, the OPUC issued an order (2008 Order) that required PGE to provide refunds of $33 million, including interest, which were completed in 2010. Following appeals, the 2008 Order was upheld by the Oregon Court of Appeals in February 2013 and by the Oregon Supreme Court (OSC) in October 2014.

In 2003, in two separate legal proceedings, lawsuits were filed in Marion County Circuit Court (Circuit Court) against PGE on behalf of two classes of electric service customers. The class action lawsuits seek damages totaling $260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment in Trojan.

In August 2006, the OSC issued a ruling ordering the abatement of the class action proceedings. The OSC concluded that the OPUC had primary jurisdiction to determine what, if any, remedy could be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

The OSC further stated that if the OPUC determined that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part. The OSC added that, if the OPUC determined that it cannot provide a remedy, the court system may have a role to play. The OSC also ruled that the plaintiffs retain the right to return to the Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. In October 2006, the Circuit Court abated the class actions in response to the ruling of the OSC.

In June 2015, based on a motion filed by PGE, the Circuit Court lifted the abatement and in July 2015, the Circuit Court heard oral argument on the Company's motion for Summary Judgment. Following oral argument on PGE's motion for summary judgment, the plaintiffs moved to amend the complaints. On February 22, 2016, the Circuit Court denied the plaintiff's motion to amend the complaint and on March 16, 2016, the Circuit Court entered a general judgment that granted the Company's motion for summary judgment and dismissed all claims by the plaintiffs. On April 14, 2016, the plaintiffs appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon.

PGE believes that the October 2, 2014 OSC decision and the recent Circuit Court decisions have reduced the risk of a loss to the Company in excess of the amounts previously recorded and discussed above. However, because the class actions remain subject to a decision in the appeal, management believes that it is reasonably possible that such a loss to the Company could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine the amount of any such loss.

Pacific Northwest Refund Proceeding

In response to the Western energy crisis of 2000-2001, the FERC initiated, beginning in 2001, a series of proceedings to determine whether refunds are warranted for bilateral sales of electricity in the Pacific Northwest wholesale spot market during the period December 25, 2000 through June 20, 2001. In an order issued in 2003, the FERC denied refunds. Various parties appealed the order to the Ninth Circuit Court of Appeals (Ninth Circuit) and, on appeal, the Ninth Circuit remanded the issue of refunds to the FERC for further consideration.

On remand, in 2011 and thereafter, the FERC issued several procedural orders that established an evidentiary hearing, defined the scope of the hearing, expanded the refund period to include January 1, 2000 through December 24, 2000 for certain types of claims, and described the burden of proof that must be met to justify abrogation of the contracts at issue and the imposition of refunds. Those orders included a finding by the FERC that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome either by: i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract; or ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest. The FERC also held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Refund proponents appealed these procedural orders at the Ninth Circuit. On December 17, 2015, the Ninth Circuit held that the FERC reasonably applied the *Mobile-Sierra* presumption to the class of contracts at issue in the proceedings and dismissed evidentiary challenges related to the scope of the proceeding. Plaintiffs on behalf of the California Energy Resources Scheduling division of the California Department of Water Resources filed a request for rehearing on February 1, 2016. By order issued April 18, 2016, the Ninth Circuit denied Plaintiffs' request for panel rehearing of its decision regarding application of the *Mobile-Sierra* presumption.

In response to the evidence and arguments presented during the hearing, in May 2015, the FERC issued an order finding that the refund proponents had failed to meet the *Mobile-Sierra* burden with respect to all but one respondent. In December 2015, the FERC denied all requests for rehearing of its order. With respect to the remaining respondent, FERC ordered additional proceedings, and in an order issued October 18, 2016, rejected the Plaintiffs' request for refunds from the respondent, finding that the Plaintiffs had not met their Mobile-Sierra burden of proof.

The Company has settled all of the direct claims asserted against it in the proceedings for an immaterial amount. The settlements and associated FERC orders did not fully eliminate the potential for so-called “ripple claims,” which have been described by the FERC as “sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund.” As a result of the FERC orders to date, there are only two sellers from whom ripple claims could arise if those orders are overturned on appeal. Both of these sellers have now authorized on-the- record representations that they would not pursue ripple claims if they were required to pay refunds. As a result, the Company does not believe that it will incur any material loss in connection with this matter.

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings, investigations, and claims that arise from time to time in the ordinary course of business, which may result in judgments against the Company. Although management currently believes that resolution of such matters, individually and in the aggregate, will not have a material impact on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management’s view of these matters may change in the future.

QUARTERLY FINANCIAL DATA

(Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2016				
Revenues, net	$ 487	$ 428	$ 484	$ 524
Income from operations	99	64	64	106
Net income	61	37	34	61
Earnings per share: *				
Basic	0.68	0.42	0.38	0.68
Diluted	0.68	0.42	0.38	0.68
2015				
Revenues, net	$ 473	$ 450	$ 476	$ 499
Income from operations	85	72	68	84
Net income	50	35	36	51
Earnings per share: *				
Basic	0.64	0.44	0.40	0.57
Diluted	0.62	0.44	0.40	0.57

* Earnings per share are calculated independently for each period presented. Accordingly, the sum of the quarterly earnings per share amounts may not equal the total for the year.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer, has evaluated the effectiveness of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company’s disclosure controls and procedures are effective.

(b) Management’s Annual Report on Internal Control over Financial Reporting

The Company’s management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The Company’s internal control over financial reporting is a process designed by, or under the supervision of, the Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company’s financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company’s internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management’s assessment was based on the framework established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2016, the Company’s internal control over financial reporting is effective.

The Company’s internal control over financial reporting, as of December 31, 2016, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company’s consolidated financial statements, as stated in their report included in Item 8.—“Financial Statements and Supplementary Data,” which expresses an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting, as of December 31, 2016.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in the Company’s internal control over financial reporting during the fourth quarter of 2016 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

On February 15, 2017, the Compensation and Human Resources Committee approved amendments to the Company’s Severance Pay Plan for Executive Employees (the “Plan”). The amendments provide that, in the event of termination of employment without cause following a Change in Control (as defined in the Plan), executive officers, including the named executive officers (NEOs), would be entitled to receive a severance payment in the amount of 52 weeks of base salary plus the target cash incentive award for the fiscal year in which the termination occurs. In addition, the amendments eliminate the four-year vesting period for full severance benefits under the Plan, so that executive officers, including each of the NEOs, would be entitled to receive full severance benefits under the Plan, regardless of their years of service.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by Item 10 is incorporated herein by reference to the relevant information under the captions “Section 16(a) Beneficial Ownership Reporting Compliance,” “Corporate Governance,” “Proposal 1: Election of Directors,” and “Executive Officers” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 26, 2017.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions “Corporate Governance—Non-Employee Director Compensation,” “Corporate Governance—Compensation Committee Interlocks and Insider Participation,” “Compensation and Human Resources Committee Report,” “Compensation Discussion and Analysis,” and “Executive Compensation Tables” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 26, 2017.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions “Security Ownership of Certain Beneficial Owners, Directors and Executive Officers” and “Equity Compensation Plans,” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 26, 2017.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption “Corporate Governance” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 26, 2017.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions “Principal Accountant Fees and Services” and “Pre-Approval Policy for Independent Auditor Services” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 26, 2017.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

The financial statements are set forth under Item 8 of this Annual Report on Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Third Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 8-K filed May 9, 2014, Exhibit 3.1).
3.2*	Tenth Amended and Restated Bylaws of Portland General Electric Company (Form 8-K filed May 9, 2014, Exhibit 3.2).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965) (File No. 001-05532-99).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 001-05532-99).
4.3*	Sixty-second Supplemental Indenture dated April 1, 2009 (Form 8-K filed April 16, 2009, Exhibit 4.1) (File No. 001-05532-99).
(10)	**Material Contracts**
10.1*	Amended and Restated Credit Agreement dated March 6, 2015 between Portland General Electric Company and Wells Fargo Bank, National Association, as Administrative Agent, Bank of America, N.A., Barclays Bank PLC, JPMorgan Chase Bank, N.A. and U.S. Bank National Association (Form 10-Q filed April 27, 2015, Exhibit 10.1).
10.2	Portland General Electric Company Severance Pay Plan for Executive Employees, as amended and restated effective February 14, 2017. +
10.3*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2) (File No. 001-05532-99). +
10.4*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18) (File No. 001-05532-99). +
10.5*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1) (File No. 001-05532-99). +
10.6*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2) (File No. 001-05532-99). +
10.7*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.3) (File No. 001-05532-99). +
10.8*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4) (File No. 001-05532-99). +
10.9*	Portland General Electric Company 2006 Stock Incentive Plan, as amended (Form 10-K filed February 27, 2008, Exhibit 10.23) (File No. 001-05532-99). +
10.10*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan (Form 8-K filed March 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.11*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.12*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers (Form 8-K filed February 26, 2008, Exhibit 10.1) (File No. 001-05532-99). +
10.13*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1) (File No. 001-05532-99). +

Exhibit Number	Description
10.14*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters for Officers and Key Employees (Form 8-K filed February 19, 2010, Exhibit 10.1). +
10.15*	Form of Directors' Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.16*	Form of Officers' and Key Employees' Performance Stock Unit Agreement (Form 10-Q filed May 3, 2012, Exhibit 10.1) (File No. 001-05532-99). +
(12)	**Statements Re Computation of Ratios**
12.1	Computation of Ratio of Earnings to Fixed Charges.
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.
(101)	**Interactive Data File**
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Incorporated by reference as indicated.
\+ Indicates a management contract or compensatory plan or arrangement.

Certain instruments defining the rights of holders of other long-term debt of PGE are omitted pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K because the total amount of securities authorized under each such omitted instrument does not exceed 10% of the total consolidated assets of the Company and its subsidiaries. PGE hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Upon written request to Investor Relations, Portland General Electric Company, 121 S.W. Salmon Street, Portland, Oregon 97204, the Company will furnish shareholders with a copy of any Exhibit upon payment of reasonable fees for reproduction costs incurred in furnishing requested Exhibits.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 16, 2017.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ JAMES J. PIRO

James J. Piro

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 16, 2017.

Signature	Title
/s/ JAMES J. PIRO **James J. Piro**	*President, Chief Executive Officer, and Director* (principal executive officer)
/s/ JAMES F. LOBDELL **James F. Lobdell**	*Senior Vice President of Finance, Chief Financial Officer, and Treasurer* (principal financial and accounting officer)
/s/ JOHN W. BALLANTINE **John W. Ballantine**	*Director*
/s/ RODNEY L. BROWN, JR. **Rodney L. Brown, Jr.**	*Director*
/s/ JACK E. DAVIS **Jack E. Davis**	*Director*
/s/ DAVID A. DIETZLER **David A. Dietzler**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ KATHRYN J. JACKSON **Kathryn J. Jackson**	*Director*
/s/ NEIL J. NELSON **Neil J. Nelson**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*
/s/ CHARLES W. SHIVERY **Charles W. Shivery**	*Director*

EXHIBIT 10.2

February 15, 2017

PORTLAND GENERAL ELECTRIC COMPANY

SEVERANCE PAY PLAN FOR EXECUTIVE EMPLOYEES

Amended and Restated
Effective February 15, 2017

PORTLAND GENERAL ELECTRIC COMPANY
SEVERANCE PAY PLAN
FOR EXECUTIVE EMPLOYEES

PURPOSE

This Portland General Electric Company Severance Pay Plan for Executive Employees, as amended from time to time (the "Plan") defines the benefits provided to executive employees whose employment is permanently terminated by Portland General Electric Company (the "Company") under certain circumstances.

ARTICLE I. EFFECTIVE DATE

1.1 The Plan, as amended and restated, shall be effective February 15, 2017 (the "Effective Date").

ARTICLE II. DEFINED TERMS

The following terms are defined in this Plan, as described below.

2.1 "Board" shall mean the Board of Directors of the Company.

2.2 "Cause" shall mean:

(i) with respect to a termination that occurs outside the Protection Period, a violation of Company standards of performance, conduct or attendance (as construed by the Company in its sole discretion); and

(ii) with respect to a termination of an Employee that occurs during the Protection Period, conduct involving one or more of the following: (i) the substantial and continuing failure of the Employee to perform substantially all of his or her duties to the Company in accordance with the Employee's obligations and position with the Company (other than any such failure resulting from incapacity due to physical or mental illness), after 30 days' notice from the Company, such notice setting forth in reasonable detail the nature of such failure, and in the event the Employee fails to cure such breach or failure within 30 days of notice from the Company, if such breach or failure is capable of cure; (ii) the violation of a Company policy, which violation could reasonably be expected to result in termination; (iii) dishonesty, gross negligence, breach of fiduciary duty; (iv) the commission by the Employee of an act of fraud or embezzlement, as found by a court of competent jurisdiction; (v) the conviction of the Employee of a felony; or (vi) a material breach of the terms of an agreement with the Company, provided that the Company provides the Employee with adequate notice of such breach and the Employee fails to cure such breach, if the breach is reasonably curable, within thirty (30) days after receipt of such notice.

2.3 "Change in Control" shall mean any of the following events:

(i) Any person (as such term is used in Section 14(d) of the Securities Exchange Act of 1934) becomes the "beneficial owner" (as determined pursuant to Rule 14d-3 under the Securities Exchange Act of 1934), directly or indirectly, of securities of the Company representing more than thirty percent (30%) of the combined voting power of the Company's then outstanding voting securities; or

(ii) During any period of two (2) consecutive years (not including any period prior to the Effective Date), individuals who at the beginning of such period constitute the members of the Board and any new director whose election to the Board or nomination for election to the Board by the Company's stockholders was approved by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors at the beginning of the period or whose election or nomination for election was previously so approved, cease for any reason to constitute a majority of the Board; or

(iii) The Company shall merge with or consolidate into any other corporation or entity, other than a merger or consolidation which would result in the holders of the voting securities of the Company outstanding immediately prior thereto holding immediately thereafter securities representing more than fifty percent (50%) of the combined voting power of the voting securities of the Company or such surviving entity outstanding immediately after such merger or consolidation; or

(iv) The stockholders of the Company approve a plan of complete liquidation of the Company or an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets.

2.4 "Code" shall mean the Internal Revenue Code of 1986, as amended.

2.5 "Committee" shall have the meaning set forth in Article IX of the Plan.

2.6 "Company" shall have the meaning set forth in the Purpose section of the Plan.

2.7 "Divested Employer" shall have the meaning set forth in Article III of the Plan.

2.8 "Effective Date" shall have the meaning set forth in Article I of the Plan.

2.9 "Employee" shall mean any regular employee of the Company, or any such affiliate of the Company as the Board may determine from time to time may participate in the Plan, who is employed on the payroll of the Company or any such affiliate, and whose position with the Company is at the level of vice president or above.

2.10 "ERISA" shall have the meaning set forth in Article VIII of the Plan.

2.11 "Good Reason" shall mean the occurrence of any of the following conditions: (i) a material adverse change in the nature of the Employee's duties or responsibilities, provided that merely ceasing to be an officer of a public company shall not, by itself, constitute a material adverse change for purposes of this provision; (ii) a material reduction in the Employee's base compensation or incentive compensation opportunities, or as they respectively may be increased thereafter from time to time; or (iii) a mandatory relocation of Employee's principal place of work in excess of 50 miles. Notwithstanding the foregoing, a condition shall not constitute "Good Reason" for purposes of the Plan unless (a) within 30 days following the first occurrence of such condition, the Employee delivers written notice to the Company of his or her intent to terminate employment for Good Reason based on such condition, and (b) within 30 days following its receipt of such notice, the Company has not substantially cured such condition.

2.12 "Key Employee" shall mean an Employee treated as a "specified employee" as of his Separation from Service under Code section 409A(a)(2)(B)(i), i.e., a key employee (as defined in Code section 416(i) without regard to paragraph (5) thereof) of the Company or its affiliates if the Company's or its affiliate's stock is publicly traded on an established securities market or otherwise. Key Employees shall be determined in accordance with Code section 409A using a December 31 identification date. A listing of Key Employees as of an identification date shall be effective for the 12-month period beginning on the April 1 following the identification date.

2.13 "Plan" shall have the meaning set forth in the Purpose section of the Plan.

2.14 "Protection Period" shall mean the 24-month period beginning on the date of the first instance of a Change in Control following the Effective Date.

2.15 "Retirement" shall mean an Employee's voluntary termination of employment on or after an "early retirement date" (as such term is defined in Section 5.3 of the Portland General Electric Company Pension Plan, as amended from time to time).

2.16 "Separation from Service" shall mean a "separation from service" as defined under Code section 409A and regulations issued thereunder.

ARTICLE III. TERMINATION OUTSIDE PROTECTION PERIOD

3.1 Eligibility to Participate. Outside the Protection Period, all Employees are eligible to participate in the Plan, other than any Employee: (i) who is covered under the provisions of another severance pay plan that provides for a form of severance remuneration upon termination of employment; (ii) who has a written employment contract that provides for a form of severance remuneration upon termination of employment; (iii) who is not designated as a full time active employee of the Company or a participating affiliate (including an Employee on an unpaid personal leave of absence, unless the Employee's reemployment rights are protected by applicable law, in which case he shall be treated as a full time active employee for purposes of this Plan), or (iv) who is designated as a temporary employee or contract employee on the payroll of the Company or a participating affiliate.

3.2 No Benefits Unless Involuntary Termination by Company or Voluntary Termination for Good Reason. Outside the Protection Period, no Employee who voluntarily terminates employment with the Company or a participating affiliate (including due to Retirement) or whose employment terminates due to death or disability shall receive a severance benefit under the Plan, unless the Employee voluntarily terminates employment for Good Reason within 90 days following the first occurrence of the condition constituting Good Reason.

3.3 Additional Exclusions. Outside the Protection Period, an Employee will not be eligible to receive a severance benefit under this Plan if:

(a) Termination for Cause. The Employee's employment is terminated for Cause;

(b) Short Term Layoff with Potential of Recall. The Employee is laid off for a period of short duration and subject to recall within a reasonable time, as determined by the Company;

(c) Offer of Position. In connection with an Employee's removal from a position, the Employee (i) receives an offer of employment from the Company or a Divested Employer or any of their respective affiliates, provided that the conditions of such offer would not have constituted Good Reason, or (ii) accepts an offer of employment at any salary or location from the Company or a Divested Employer or any of their respective affiliates, regardless of whether the requirements of (i) above are satisfied;

(d) Other Severance or Termination Benefits. The Employee receives extra or additional consideration outside of the Plan in connection with the Employee's termination of, or retirement from, employment (including by way of example, but not limited to, enhanced retirement benefits or incentive remuneration), and the Committee makes a determination that a severance benefit under the Plan should not be paid; or

(e) Other Special Circumstances. Special circumstances exist for which the Chief Executive Officer of the Company makes a written determination that a severance benefit will not be paid.

"Divested Employer" means (i) a division, subsidiary, venture or partnership, or other business segment of the Company or an affiliate of the Company, which has been or is proposed to be divested, or (ii) the proposed or actual purchaser or acquirer thereof, by reason of ownership or acquisition of stock, assets or otherwise, and includes any affiliate of such Divested Employer.

3.4 Severance Benefit Payable; Waiver and Release Required. An Employee whose employment is permanently terminated by the Company or a participating affiliate without Cause, or who voluntarily terminates employment for Good Reason within 90 days following the first occurrence of the condition constituting Good Reason, in either case outside the Protection Period, will be eligible to receive 52 weeks of the Employee's base pay. In order to receive these severance benefits, the Employee must timely execute and deliver to the Company an agreement of separation that shall contain a waiver and release of all rights and claims relating to the Employee's employment by the Company and its affiliates, and the termination of that employment by the Company or its affiliate, and that shall contain such other provisions as approved and required by the Company, in its sole discretion, within a time limit and in a form prepared by and acceptable to the Company.

ARTICLE IV. TERMINATION DURING PROTECTION PERIOD

4.1 Eligibility to Participate. During the Protection Period, all Employees are eligible to participate in the Plan, other than any Employee who has a written employment contract that provides for a form of severance remuneration upon termination of employment.

4.2 No Benefits Unless Involuntary Termination by Company or Voluntary Termination for Good Reason. During the Protection Period, no Employee who voluntarily terminates employment with the Company or a participating affiliate (including due to Retirement) or whose employment terminates due to death or disability shall receive a severance benefit under the Plan, unless the Employee voluntarily terminates employment for Good Reason within 90 days following the first occurrence of the condition constituting Good Reason.

4.3 Termination for Cause. During the Protection Period, an Employee will not be eligible to receive a severance benefit under this Plan if the Employee's employment is terminated for Cause.

4.4 Severance Benefit Payable; Waiver and Release Required. An Employee whose employment is permanently terminated by the Company or a participating affiliate without Cause, or who voluntarily terminates employment for Good Reason within 90 days following the first occurrence of the condition constituting Good Reason (or such longer period as the Company and the Employee may agree to), in either case during the Protection Period, will receive the severance benefit provided for in Section 4.5 of the Plan, provided that the Employee timely executes and delivers to the Company an agreement of separation that shall contain a waiver and release substantially in the form set forth in Appendix A hereto.

4.5 Amount of Severance Benefit. The severance benefit payable under the Plan during the Protection Period is: (a) 52 weeks of the Employee's base pay in effect immediately prior to the start of the Protection Period or as it may be increased thereafter, plus (b) the Employee's target annual cash incentive award in effect immediately prior to the start of the Protection Period or as it may be increased thereafter.

ARTICLE V. PAYMENT OF Severance Benefit

5.1 Payment of Benefit. Cash severance benefits to which an Employee becomes entitled under Article III or IV shall be paid in a lump sum on the 60th day following Separation from Service. Notwithstanding the foregoing, severance benefits shall be paid to a Key Employee on the first day of the seventh month following the Employee's Separation from Service (or, if earlier, the first day of the month after the Employee's death).

5.2 Income Taxes. The payment of benefits under the Plan is subject to all applicable federal, state and local tax withholding and generally constitutes taxable income to the recipient. Employees are advised to consult with their personal tax advisor for more information.

5.3 Treatment of Parachute Payments. Notwithstanding anything in this Plan to the contrary, if any payment or benefit to which an Employee is entitled under this Plan or otherwise would, either alone or together with all other payments and benefits to which such Employee is entitled, but for the application of this Section 5.3, result in an excise tax to the Employee under Section 4999 of the Code, then such payments and benefits shall be payable either (a) in full or (b) in such lesser amount as would result in no portion of any payments or benefits to such Employee being subject to the excise tax under Section 4999 of the Code, whichever of the foregoing options (a) or (b) results in the Employee's receipt, on an after-tax basis, of the greater amount of payments and benefits. To the extent the Employee would receive a reduced amount pursuant to this Section 5.3, the Employee's payments and benefits shall be reduced, to the extent necessary, by first cancelling cash payments under this Plan, then any other cash payments, and then cancelling the acceleration of vesting of equity awards.

The Company shall select a nationally recognized accounting firm to perform any calculations and other determinations required by this Section 5.3, which calculations and determinations shall be final, conclusive and binding on the Company, the Employee and all other interested parties.

ARTICLE VI. REEMPLOYMENT OF TERMINATED EMPLOYEE

6.1 In the event an Employee who receives a severance benefit under the Plan is reemployed by the Company or any affiliate or is employed by a Divested Employer or any affiliate within one (1) year after the Employee's termination of employment, the Employee shall be required to refund to the Company an amount equal to the amount of severance benefit less the amount of base pay the Employee would have received had the Employee remained employed at the Employee's rate of base pay at termination until the date of the Employee's reemployment or employment.

ARTICLE VII. MALFEASANCE IS BREACH OF PORTLAND GENERAL ELECTRIC COMPANY POLICY

7.1 Any officer or employee of the Company or a participating affiliate, including an Employee who receives a severance benefit under the Plan, who intentionally participates in a mischaracterization of the reason for an Employee's termination of employment, whereby an Employee receives a greater severance benefit under the Plan or any other compensatory plan, program or policy of the Company or any affiliate, than such Employee would otherwise be entitled, shall work a malfeasance against the Company and the Plan, and the Company and the Plan may seek any remedy available in equity or at law due to such malfeasance.

ARTICLE VIII. ERISA PROVISIONS

8.1 ERISA. The Plan is established pursuant to, and governed by, the Employee Retirement Income Security Act, as amended ("ERISA").

8.2 Funding. The benefits provided herein shall be funded by the Company's general assets. The Plan shall constitute an unfunded mechanism for the Company to pay Plan benefits to Employees determined to be eligible for payments hereunder. No fund or trust is created with respect to the Plan, and no Employee shall have any security or other interest in the assets of the Company.

8.3 Fiscal Year. The Fiscal Year of the Plan shall be the same fiscal year adopted by the Company for accounting purposes.

8.4 Cost of Plan. The entire cost of the Plan shall be borne by the Company and no contributions shall be required of the eligible Employees, except as specifically provided herein.

8.5 Named Fiduciary. The Company is the sponsor and the named fiduciary of the Plan.

ARTICLE IX. ADMINISTRATION OF THE PLAN

9.1 Appointment of Committee. The general administration of the Plan shall be vested in the Compensation and Human Resources Committee of the Board (the "Committee"). For purposes of ERISA, the Committee shall be the Plan "administrator" and shall be a "fiduciary" with respect to the administration of the Plan.

9.2 Compensation, Bonding and Expenses of Members. The Members of the Committee shall not receive compensation with respect to their services for the Committee in respect of this Plan. To the extent required by ERISA or other applicable law, or required by the Company, members of the Committee shall furnish bond or security for the performance of their duties hereunder. Any expenses properly incurred by the Committee incident to the administration, termination or protection of the Plan, including the cost of furnishing any bond or security, shall be paid by the Company.

9.3 Committee Powers and Duties. The Committee shall supervise the administration and enforcement of the Plan according to the terms and provisions hereof and shall have the sole discretionary authority and all powers necessary to accomplish these purposes, including, but not by way of limitation, the right, power, authority and duty to:

(a) make rules, regulations and procedures for the administration of the Plan which are not inconsistent with the terms and provisions hereof, provided such rules, regulations and procedures are evidenced in writing and copies thereof are delivered to the Company;

(b) construe and interpret all terms, provisions, conditions and limitations of the Plan;

(c) correct any defect, supply any omission, construe any ambiguous or uncertain provisions, or reconcile any inconsistency that may appear in the Plan, in such manner and to such extent as it shall deem expedient to carry the Plan into effect;

(d) employ and compensate such accountants, attorneys, investment advisors and other agents and employees as the Committee may deem necessary or desirable in the proper and efficient administration of the Plan;

(e) determine all questions relating to eligibility;

(f) determine the amount of any benefits hereunder and to prescribe procedures to be followed by distributees in obtaining benefits;

(g) prepare, file and distribute, in such manner as the Committee determines to be appropriate, such information and material as is required by the reporting and disclosure requirements of ERISA; and

(h) make a determination as to the right of any person to receive a benefit under the Plan.

9.4 Standard of Review. Any decision, determination, or other action by the Committee shall be final and binding upon the parties, and shall only be subject to judicial review under an abuse of discretion standard.

9.5 Information to Committee. The Company shall supply full and timely information to the Committee relating to Employees and such pertinent facts as the Committee may require. When making a determination in connection with the Plan, the Committee shall be entitled to rely upon the aforesaid information furnished by the Company.

ARTICLE X. CLAIMS PROCEDURE.

10.1 Claim for Benefits. If an Employee is not paid benefits under the Plan at the time of termination of his or her employment, any claim for benefits payable under the Plan must be made in writing and received by the Company within ninety (90) days of the Employee's termination of employment. Claims for benefits under the Plan shall be made in writing to the Company.

10.2 Denial of Claim. If a claim for benefits is wholly or partially denied, the Company shall notify the claimant of the Plan's adverse benefit determination within a reasonable period of time, but not later than ninety (90) days after receipt of the claim by the plan, unless the Company determines that special circumstances require an extension of time for processing the claim. If the Company determines that an extension of time for processing is required, written notice of the extension shall be furnished to the claimant prior to the termination of the initial ninety-day period. In no event shall such extension exceed a period of ninety (90) days from the end of such initial period. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Plan expects to render the benefit determination. The period of time within which a benefit determination is required to be made shall begin at the time a claim is filed in accordance with the reasonable procedures established by the Committee, without regard to whether all the information necessary to make a benefit determination accompanies the filing.

10.3 Notice of Claim Denial. The Company shall provide a claimant with written or electronic notification of any adverse benefit determination. Any electronic notification shall comply with the standards imposed by 29 CFR 2520.104b-l(c)(l)(i), (iii), and (iv). The notification shall set forth, in a manner calculated to be understood by the claimant: (i) the specific reason or reasons for the adverse determination; (ii) reference to the specific plan provisions on which the determination is based; (iii) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation of why such material or information is necessary; and (iv) a description of the Plan's review procedures and the time limits applicable to such procedures, including a statement of the claimant's right to bring a civil action under section 502(a) of ERISA following an adverse benefit determination on review. Such notification shall provide the claimant the opportunity to submit written comments, documents, records, and other information relating to the claim for benefits. The claimant shall be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant's claim for benefits. A document, record, or other information shall be considered "relevant" to a claimant's claim if such document, record, or other information: (i) was relied upon in making the benefit determination; (ii) was submitted, considered, or generated in the course of making the benefit determination, without regard to whether such document, record, or other information was relied upon in making the benefit determination; or (iii) demonstrates compliance with the administrative processes and safeguards established by the Committee to ensure and to verify that benefit claim determinations are made in accordance with governing plan documents and that, where appropriate, the Plan provisions have been applied consistently with respect to similarly situated claimants.

10.4 Review of Denial. Within sixty (60) days of the receipt by the claimant of written or permitted electronic notification of an adverse benefit determination, the claimant may file a written request with the Committee that it conduct a full and fair review of the denial of the claimant's claim for benefits. A review by the Committee shall take into account all comments, documents, records, and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The period of time within which a benefit determination on review is required to be made shall begin at the time an appeal is filed in accordance with the reasonable procedures established by the Committee, without regard to whether all the information necessary to make a benefit determination on review accompanies the filing. In the event that a period of time is extended due to a claimant's failure to submit information necessary to decide a claim, the period for making the benefit determination on review shall be tolled from the date on which the notification of the extension is sent to the claimant until the date on which the claimant responds to the request for additional information.

10.5 Decision on Review. The Committee shall notify a claimant, in accordance with Section 10.6 of the Plan, of its benefit determination on review of a claimant's appeal of an adverse benefit determination within a reasonable period of time, but not later than sixty days after receipt of the claimant's request for review by the Committee, unless the Committee determines that special circumstances (such as the need to hold a hearing, if the Plan's procedures provide for a hearing) require an extension of time for processing the claim. If the Committee determines that an extension of time for processing is required, written notice of the extension shall be furnished to the claimant prior to the termination of the initial sixty-day period. In no event shall such extension exceed a period of sixty days from the end of the initial period. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Committee expects to render the determination on review.

10.6 Notice of Decision on Review. The Committee shall notify the claimant of the benefit determination as soon as possible, but not later than five (5) days after the benefit determination is made with written or electronic notification of the Committee's benefit determination of the claimant's appeal of the benefit denial. Any electronic notification shall comply with the standards imposed by 29 CFR 2520.104b-1(c)(I)(i), (iii), and (iv). In the case of an adverse benefit determination, the notification shall set forth, in a manner calculated to be understood by the claimant: (i) the specific reason or reasons for the adverse determination; (ii) reference to the specific plan provisions on which the benefit determination is based; (iii) a statement that the claimant is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant's claim for benefits; and (iv) a statement of the claimant's right to bring an action under section 502(a) of ERISA.

ARTICLE XI. TERMINATION AND AMENDMENT OF PLAN

11.1 Termination of Plan. The Company, by action of the Committee, may terminate the Plan at any time outside the Protection Period, without prior notice. The Company may not terminate the Plan during the Protection Period.

11.2 Benefit upon Termination of Plan. Upon termination of the Plan, except with respect to benefits then in pay status, all rights to benefits hereunder, if any, shall cease.

11.3 Amendment of Plan. The severance benefits provided for in the Plan are not vested benefits. Accordingly, the Company reserves the right in its sole and absolute discretion, to amend or modify the Plan, in whole or in part, including any or all of the provisions of the Plan, by action of the Committee, without prior notice; provided that the Plan may not be amended during the Protection Period if such amendment would adversely affect the rights of an Employee hereunder without such Employee's consent. The Plan supersedes any severance benefit policies, plans, practices or arrangements applicable to the Employees that may have been in force prior to the Effective Date.

ARTICLE XII. MISCELLANEOUS

12.1 No Contract of Employment. The Plan does not constitute or imply the existence of an employment contract between the Company or any participating affiliate and any Employee. Employment with the Company is "at will".

12.2 Governing Law; Venue. To the extent not governed by federal law, the Plan shall be interpreted under the laws of the State of Oregon notwithstanding any conflict of law principles. Venue for all claims and actions related to or arising under the Plan shall be exclusively in the courts of the State of Oregon.

12.3 Gender. Wherever in this instrument words are used in the masculine or neuter gender, they shall be read and construed as in the masculine, feminine or neuter gender whenever they would so apply, and vice versa. Wherever words appear in the singular or plural, they shall be read and construed as in the plural or singular, respectively, wherever they would so apply.

12.4 Auxiliary Documents. Each Employee does, by his acceptance of potential benefits under the Plan, agree to execute any documents that may be necessary or proper in the carrying out of the purpose and intent of the Plan.

12.5 Code Section 409A. The Plan is intended to comply with Code section 409A and official guidance issued thereunder. Notwithstanding any other provision of this Plan, this Plan shall be interpreted, operated and administered in a manner consistent with these intentions.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________________

Anne Mersereau

Vice President, Administration

APPENDIX A

Form of Separation Agreement and Release of Claims

Portland General Electric Company
121 SW Salmon Street Portland, Oregon 97204
PortlandGeneral.com

[NAME]
[ADDRESS]

Dear **[NAME]**:

This agreement sets forth our understanding with respect to certain terms and conditions of your separation from service with Portland General Electric Company ("PGE"), including benefits you are entitled to under the Portland General Electric Company Severance Pay Plan for Executive Employees ("Severance Pay Plan") and the Portland General Electric Company Outplacement Assistance Plan ("Outplacement Assistance Plan").

1. You hereby agree to the following release, representations and covenants:

> In consideration of the severance benefits being provided to me under the Severance Pay Plan and Outplacement Assistance Plan, I, **[NAME]**, hereby release, acquit, and forever discharge, and covenant not to sue or pursue, either individually or as part of a class, any claim as described below, against PGE, its successor corporations, or any corporations or divisions which control, are under common control with or are controlled by PGE, or any of their respective past, present, and future directors, officers, employees, agents, contractors, and insurers, and their successors, individually or collectively, any person who might be entitled to claim indemnity from any of the aforementioned under contract or law, or any and all other persons or entities who might be claimed to be liable for actions of any of the aforementioned entities (collectively, the "Released Parties").
>
> This release and covenant not to sue is intended to apply to any and all claims and liabilities of every nature and kind in any way related to or arising out of my employment with PGE, or which might be asserted under local, state, or federal authorities, including but not limited to claims for additional compensation, benefits, reinstatement, reemployment, injunctive relief, reasonable accommodation, damages of any nature, penalties, or attorneys' fees, including but not limited to any and all claims based upon the Oregon statutes dealing with employment matters (ORS 652, 653, and 659), Title VII of the Civil Rights Act of 1964; the Fair Labor Standards Act; the Equal Pay Act of 1963; the Age Discrimination in Employment Act of 1967; the Older Workers Benefit Protection Act of 1990; the Civil Rights Act of 1866 and 1871 (42 USC 1981-1988), the Civil Rights Act of 1991; the Employment Retirement Income Security Act ("ERISA"); the Rehabilitation Act of 1973; the Vietnam Era Veterans Readjustment Assistance Act of 1974; Uniformed Services Employment and Reemployment Rights Act of 1994; the Energy Reorganization Act of 1974; the Americans With Disabilities Act of 1990; the Worker Adjustment and Retraining Notification Act; and Executive Order 11246, all as amended, all regulations under such authorities, and any contract (either expressed or implied, oral or written), tort, or other common law theory which might apply.

I represent that I have not filed any complaints, charges, or lawsuits against the Released Parties, either individually or as part of a class, with any governmental agency or court with respect to any matter released herein and that I have no intent to do so at any time hereafter.

I am currently unaware of any claim, right, demand, debt, action, obligation, liability, or cause of action that I may have against the Released Parties, either individually or as part of a class, which has not been released in this agreement. I expressly agree that this is a full and final release covering all unknown, undisclosed, and unanticipated losses, wrongs, claims, or damages I may have against the Released Parties, which may have arisen from any act or omission prior to the later of the effective date of this agreement or my termination of employment, arising out of or related to my employment or the termination thereof.

Notwithstanding anything that may be construed to the contrary in the previous paragraphs, I understand that nothing in this agreement shall be construed to prohibit me from reporting any suspected instance of illegal activity of any nature, any nuclear safety concern, any workplace safety concern, or any public safety concern, to the United States Nuclear Regulatory Commission, the United States Department of Labor, or any other federal or state governmental agency, and shall not be construed to prohibit me from participating in any way in any state or federal administrative, judicial, or legislative proceeding or investigation with respect to any illegal activity of any nature, any nuclear safety concern, any workplace safety concern, or any public safety concern, not constituting the reassertion of claims and matters resolved and terminated by the preceding paragraphs. Further, nothing in this agreement shall be construed to prohibit me from filing a charge or participating in any manner in an investigation, hearing or proceeding under the laws enforced by the U.S. Equal Employment Opportunity Commission, although this full and final release prevents any recovery by me as a result of such charge, investigation, hearing or proceeding.

I will use my best effort to maintain all of the terms and conditions of this Agreement in strict confidence. To fulfill this obligation, I will not directly or indirectly communicate, make known, or divulge to any person, agency or court, except my spouse, accountant or attorney, any information whatsoever regarding this Agreement, unless compelled to do so by legal process or unless prior approval is given in writing by PGE’s General Counsel. I will direct my spouse, accountant, and attorney not to breach this confidentiality commitment.

This release does not extend to any rights or claims I may have under any “employee benefit plans” [within the meaning of Section 3(3) of the Employee Retirement Income Security Act of 1974, as amended (“ERISA”] maintained by Enron Corp., PGE or Portland General Holdings, Inc. in the course of my employment, as well as any rights or claims against Enron Corp., PGE or Portland General Holdings, Inc. for unpaid benefits under the Portland General Holdings, Inc. Management Deferred Compensation Plan or the Supplemental Executive Retirement Program, if applicable.

I agree that I shall, by the time this agreement is executed, return to PGE all originals and copies of PGE files and documents, tapes, disks and other tangible items containing PGE’s Confidential or Proprietary Information that are in my possession or control. I further agree not to disclose to third parties, or make any use of for personal gain, in connection with future employment or otherwise, Confidential or Proprietary Information, unless compelled to do so by legal process, and shall not reproduce any Confidential or Proprietary Information in any form without express written permission of PGE. For the purposes of this Agreement, “Confidential or Proprietary

Information" shall mean any information relating to PGE or its businesses including, but not limited to, business plans, negotiations and contracts with customers or other companies, customer lists, employee lists, information personal or proprietary to employees and/or customers, financial information, marketing strategies and computer programs and any other information relating to PGE or its businesses which PGE takes measures to keep confidential and/or to prevent disclosure to competitors; provided, however, that Confidential or Proprietary Information shall not include information which is generally known or available to the public through no breach of this agreement by me.

2. PGE will provide you final distribution of all amounts payable to you under the Severance Pay Plan (totaling approximately $**[X]**) during the period provided for under the plan (expected to be approximately **[X]** following your termination date). The following taxes will be withheld: State of Oregon and federal withholding.

3. As a management employee, you are eligible to participate in the Outplacement Assistance Plan. Each management employee will be offered the services of a professional outplacement firm selected by PGE for not less than three months, with the option to extend the services for an additional three months or such additional period as permitted by the Benefits Administration Committee. PGE will pay 100 percent of the cost of your outplacement services. **[NAME]**, PGE Plan Administrator, 121 SW Salmon Street, Portland, Oregon 97204, 503-464-2023, will coordinate your start date with the outplacement consultant. You are responsible for initiating the services of an outplacement consultant within 30 days of termination of employment. Please notify **[NAME]** of your intentions as soon as possible.

4. If you are rehired within one year of the date of termination, you will be required to repay that portion of your severance benefit which is in excess of the amount of base pay you would have received if you had remained employed at your rate of base pay at termination until the date of your reemployment.

5. PGE will provide employment references stating your term of employment and job title. Any information beyond this must be authorized by you in writing.

6. Eligibility factor(s) to qualify for the Severance Pay Plan and Outplacement Assistance Plan are as set forth in the plan documents.

   You are the only employee eligible for the program at this time; therefore, a list of eligible job categories is not being provided.

7. Please write below on the lines provided: "I am agreeing to the release, representations and covenants forth in section 1 voluntarily with full understanding of their effect."

____
____
____

8. This agreement was first presented to you for consideration on **[DATE]**.

9. **WE ADVISE THAT YOU SEEK THE ADVICE OF A LAWYER BEFORE SIGNING THIS AGREEMENT. YOU HAVE FORTY-FIVE (45) DAYS TO CONSIDER THIS AGREEMENT BEFORE SIGNING.**

10. You have seven (7) days to revoke following execution of this agreement. The agreement will not be effective or enforceable until seven (7) days have expired from the day you sign it.

By: _________ Date _______

By: _________ Date _______

By: _________ Date _______

Enclosures

Employee: Ÿ Complete Line 7
Ÿ Sign and date
Ÿ Retain a copy of this document for your records
Ÿ Return the entire original to **[NAME]**, 1WTC0605

EXHIBIT 12.1

PORTLAND GENERAL ELECTRIC COMPANY

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(Dollars in thousands)

	Years Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
Income from continuing operations before income taxes	$ 243,108	$ 216,818	$ 236,679	$ 125,758	$ 205,406
Total fixed charges	132,654	135,956	128,515	118,189	122,851
Total earnings	$ 375,762	$ 352,774	$ 365,194	$ 243,947	$ 328,257
Fixed charges:					
Interest expense	$ 111,539	$ 113,861	$ 96,068	$ 100,818	$ 107,992
Capitalized interest	10,820	12,520	22,441	6,892	3,699
Interest on certain long-term power contracts	4,946	5,140	5,137	5,996	6,643
Estimated interest factor in rental expense	5,349	4,435	4,869	4,483	4,517
Total fixed charges	$ 132,654	$ 135,956	$ 128,515	$ 118,189	$ 122,851
Ratio of earnings to fixed charges	2.83	2.59	2.84	2.06	2.67

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-214580 on Form S-3 and Registration Statements Nos. 333-135726, 333-142694, and 333-158059 on Forms S-8 of our report dated February 16, 2017, relating to the financial statements of Portland General Electric Company and subsidiaries, and the effectiveness of Portland General Electric Company’s internal control over financial reporting, appearing in this Annual Report on Form 10-K of Portland General Electric Company for the year ended December 31, 2016.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 16, 2017

EXHIBIT 31.1

CERTIFICATION

I, James J. Piro, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 16, 2017

/s/ JAMES J. PIRO

James J. Piro

President and

Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, James F. Lobdell, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 16, 2017

/s/ JAMES F. LOBDELL

James F. Lobdell

Senior Vice President of Finance, Chief Financial Officer, and Treasurer

EXHIBIT 32.1

**CERTIFICATIONS PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED
PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

We, James J. Piro, President and Chief Executive Officer, and James F. Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the “Company”), hereby certify that the Company’s Annual Report on Form 10-K for the year ended December 31, 2016, as filed with the Securities and Exchange Commission on February 17, 2017 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the “Report”), fully complies with the requirements of that section.

We further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JAMES J. PIRO	/s/ JAMES F. LOBDELL
James J. Piro	**James F. Lobdell**
President and Chief Executive Officer	*Senior Vice President of Finance, Chief Financial Officer and Treasurer*
Date: February 16, 2017	Date: February 16, 2017