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, 2015

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, 2015, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $2,930,492,732. For purposes of this calculation, executive officers and directors are considered affiliates.

As of January 29, 2016, there were 88,793,297 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 27, 2016.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2015

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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 Generating Station 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
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	Standard & Poor’s Ratings Services
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). As PGE is a net short utility, its retail load requirement is met with both Company-owned generation and power purchased in the wholesale market. The Company 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 was incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange, and operates as a single 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 52 incorporated cities, of which Portland and Salem are the largest. The Company estimates that at the end of 2015 its service area population was 1.8 million, comprising approximately 46% of the population of the state of Oregon. During 2015, the Company added nearly ten thousand customers and as of December 31, 2015, served a total of 852,164 retail customers.

PGE had 2,646 employees as of December 31, 2015, with 764 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 713 and 51 employees and expire at the end of February 2016 (the Company is currently in negotiation to renew or extend), 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

PGE is subject to federal and state of Oregon regulation, both of which can have a significant impact on the operations of the Company. In addition to those 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.

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.

FERC Regulation

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. 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. Re-authorization for continued use of such rates requires the filing of triennial market power studies with the FERC. The Company will file its next updated triennial market power study in 2016.

PGE also has reporting requirements to the FERC for any change in status that departs from the characteristics that the FERC relied upon in authorizing sales at market-based rates, including increases in net generation capacity.

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 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 in 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 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.

Pipeline—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, and is the operator of record of, the Kelso-Beaver 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 Kelso-Beaver 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 Federal Power Act, 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 Federal Power Act, 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 Federal Power Act 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.

NRC Regulation

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."

State of Oregon Regulation

PGE is subject to the jurisdiction of the OPUC, which is comprised of three members appointed by the governor of Oregon to serve non-concurrent four-year terms.

The OPUC 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 and prescribes accounting policies and practices, and reviews applications to: 1) sell utility assets; 2) engage in transactions with affiliated companies; and 3) acquire substantial influence over public utilities.

Integrated Resource Plan—Unless the OPUC directs otherwise, PGE is required to file with the OPUC an Integrated Resource Plan (IRP) within two years of its previous IRP acknowledgment order. Based on direction from the OPUC, PGE filed an update to its 2013 IRP in December 2015, and expects to file its next IRP with the OPUC in the latter half of 2016. 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 an acquisition plan for 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 most recent IRP, see "*Future Energy Resource Strategy*" in the Power Supply section in this Item 1.

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's most recent general rate case was the 2016 General Rate Case (2016 GRC), for which a final order was received in November 2015. New prices were effective in 2016, with the first price change effective January 1 and an additional price change to be effective when the Carty natural gas-fired generating plant (Carty), a 440 MW baseload resource in Eastern Oregon, located adjacent to the Boardman coal-fired generating plant (Boardman), becomes operational, provided that occurs by July 31, 2016. For additional information, see "*Capital Requirements and Financing*" and "*General Rate Cases*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

- *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. 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.

    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). Customer prices can also be adjusted to absorb a portion of the difference between each year's forecasted NVPC included in customer prices (baseline NVPC) and actual NVPC for the year. Under the PCAM, PGE shares a portion of the business risk or benefit associated with NVPC. The PCAM utilizes an asymmetrical deadband range, $15 million below, to $30 million above, baseline NVPC, within which PGE absorbs cost variances. When the variances fall outside of the deadband, the excess variance is shared, with 90% flowing to customers and 10% absorbed by the Company. Annual results of the PCAM are subject to application of a regulated earnings test, under which 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. 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. A final determination of any customer refund or collection is made by the OPUC through a public filing and review typically during the second half of the following year. 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, currently 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. The mechanism provides for: 1) collections from customers if weather adjusted energy use per customer is lower than levels included in the Company's most recent general rate case or 2) refunds to customers if weather adjusted use per customer exceeds levels included in the most recent general rate case. For additional information, see the *"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 requirement and, expects its 2015 RPS compliance report, to be made in the first half of 2016, to indicate that the 2015 requirement was achieved.

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 all 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 related to a new 1.2 MW solar facility. For additional information, see *"Legal, Regulatory and Environmental"* in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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, 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."

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.

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. Certain commercial and industrial customers also have an option to be served by an ESS for a one-year period. 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 fixed three-year or minimum five-year opt-out program.

In 2015, ESSs supplied direct access customers with energy representing 9% of the Company's total retail energy deliveries for the year, compared with 9% in 2014 and 8% in 2013. 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 2015, 2014, and 2013.

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 Energy Trust of Oregon (ETO) and other agencies for administration of these programs. Approximately, $51 million was collected from customers for this charge in both 2015, and in 2014, and $48 million in 2013.

In addition to the public purpose charge, PGE also remits to the ETO amounts collected under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. This charge was approximately 2.4%, 3.2% and 3.5% of retail revenues for applicable customers in 2015, 2014 and 2013, respectively. Under the tariff, approximately $42 million, $48 million and $50 million was collected from eligible customers in 2015, 2014 and 2013, respectively.

Siting—Oregon's Energy Facility Siting Council (EFSC) has regulatory and siting responsibility for large electric generating facilities, 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 through the sale and delivery of electricity to retail customers. The Company conducts retail electric operations exclusively in Oregon within a service area approved by the OPUC. Within its service territory, the Company 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. 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 transition adjustments for these customers.

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 8% of total retail deliveries. While the twenty largest commercial and industrial customers constituted 12% of total retail revenues in 2015, they represented eight different groups including high technology, paper manufacturing, governmental agencies, health services, and retailers.

PGE's Retail revenues (dollars in millions), retail energy deliveries (MWh in thousands), and average number of retail customers consist of the following for the years presented:

	Years Ended December 31,					
	2015		2014		2013	
Retail revenues[1] (dollars in millions):						
Residential	$ 895	50%	$ 893	51%	$ 861	51%
Commercial	662	37	657	37	619	36
Industrial	228	13	221	12	217	13
Subtotal	1,785	100	1,771	100	1,697	100
Other accrued (deferred) revenues, net	(10)	—	(8)	—	(5)	—
Total retail revenues	$ 1,775	100%	$ 1,763	100%	$ 1,692	100%
Retail energy deliveries[2] (MWh in thousands):						
Residential	7,325	38%	7,462	39%	7,702	40%
Commercial	7,511	39	7,494	39	7,441	38
Industrial	4,546	23	4,310	22	4,276	22
Total retail energy deliveries	19,382	100%	19,266	100%	19,419	100%
Average number of retail customers:						
Residential	742,467	88%	735,502	87%	728,481	87%
Commercial	105,802	12	105,231	13	104,385	13
Industrial	255	—	260	—	263	—
Total	848,524	100%	840,993	100%	833,129	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,		
	2015	2014	2013
Usage per customer (in kilowatt hours):			
Residential	9,866	10,145	10,572
Commercial	70,987	71,216	71,284
Industrial	17,485,281	16,576,500	16,257,517
Revenue per customer (in dollars):			
Residential	$ 1,139	$ 1,154	$ 1,106
Commercial	6,254	6,187	5,840
Industrial	876,866	851,149	786,390
Revenue per kilowatt hour (in cents):			
Residential	11.55¢	11.37¢	10.46¢
Commercial	8.81	8.69	8.19
Industrial	5.01	5.13	4.84

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. Economic conditions can also affect residential demand; historical data suggests that high unemployment rates contribute to a decrease in residential deliveries. 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 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% compared to 2014. Total residential deliveries for 2014 decreased 3.1% compared to 2013 as a result of warmer weather during the 2014 heating season. 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 corresponding 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 2015, the 0.2% increase in commercial deliveries compared with 2014 reflected an increase in deliveries to irrigation and service sector customers being mostly offset by lower deliveries to all other commercial sectors. Deliveries to commercial customers increased 0.7% in 2014 compared with 2013, which was primarily due to increased demand from across the majority of commercial sectors, most notably office buildings, government and education, food stores, and the warehousing sectors combined with an 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 increased 5.5% in 2015 from 2014 due to increased demand from high technology manufacturing and paper manufacturing customers. The 0.8% increase in 2014 from 2013 was due to increased demand in the high tech industry, partially offset by a decline in demand from a paper production customer. 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.

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 deferrals recorded under the RAC and the decoupling mechanism. For further information on these items, see "*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 conditions, and daily and seasonal retail demand. Wholesale revenues represented 5% of total revenues in both 2015 and 2014, and 4% in 2013.

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 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 oil sales, pole contact rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in 2015, 2014, and 2013.

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 heating or cooling.

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
2015	3,461	785
2014	3,794	653
2013	4,386	539
15-year average	4,264	453

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 (consisting of January, February and December) and summer (consisting of July, August and September) loads for the periods presented along with the corresponding peak load and month in which it occurred (in MWs):

	Winter Loads			Summer Loads		
	Average	Peak	Month	Average	Peak	Month
2015	2,509	3,255	December	2,390	3,914	July
2014	2,574	3,866	February	2,358	3,646	August
2013	2,656	3,869	December	2,278	3,527	July

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 six 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,					
	2015		2014		2013	
	Capacity	%	Capacity	%	Capacity	%
Generation:						
Thermal:						
Natural gas	1,371	30%	1,389	28%	1,163	27%
Coal	814	17	814	17	756	17
Total thermal	2,185	47	2,203	45	1,919	44
Wind (1)	717	16	717	15	450	10
Hydro (2)	495	11	494	10	494	11
Total generation	3,397	74	3,414	70	2,863	65
Purchased power:						
Long-term contracts:						
Capacity/exchange	250	5	250	5	160	3
Hydro	592	13	595	12	592	14
Wind	39	1	39	1	39	1
Solar	13	—	13	—	13	—
Other	118	3	118	2	117	3
Total long-term contracts	1,012	22	1,015	20	921	21
Short-term contracts	200	4	481	10	596	14
Total purchased power	1,212	26	1,496	30	1,517	35
Total resource capacity	4,609	100%	4,910	100%	4,380	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 nameplate 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, 2015, 2014 and 2013, 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 December 2014, PGE completed construction of PW2, a new flexible capacity resource, and Tucannon River, a new renewable resource, both discussed below. As of December 31, 2015, the Company has the Carty Generating Station (Carty) under construction, which is targeted to be placed in service in July 2016. These additional resources resulted from the competitive bidding process completed in 2013 consistent with the Company's 2009 IRP. For additional information on Carty, see "*Capital Requirements and Financing*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Thermal The Company has four natural gas-fired generating facilities: PW1, PW2, Beaver, and Coyote Springs Unit 1 (Coyote Springs). These natural gas-fired generating plants provided approximately 25% of PGE's total retail load requirement in 2015 and 18% in both 2014 and 2013.

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. For additional information, see Note 17, Jointly-owned Plant, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

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 22% of the Company's total retail load requirement in 2015, compared with 24% in 2014 and 22% in 2013.

The thermal plants provide reliable power and capacity reserves for PGE's customers. These resources have a combined capacity of 2,185 MW, representing approximately 64% of the net capacity of PGE's generating portfolio. Thermal plant availability, excluding Colstrip, was 89% in both 2015 and 2014, and 84% in 2013, while Colstrip availability was 93% in 2015, compared with 83% in 2014 and 66% in 2013. Thermal plant availability percentages for 2015 and 2014 were higher than 2013 due to unplanned outages at three plants during 2013. For additional information on the unplanned plant outages, see "*Power Operations*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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 9% of the Company's total retail load requirement in 2015 and 6% in both 2014 and 2013. Availability for these resources was 97% in 2015, compared with 94% in 2014 and 98% in 2013. 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 8% of the Company's total retail load requirement in 2015, and 9% in 2014 and in 2013, with availability of 99% in 2015, and 100% in 2014 and in 2013. 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 or after December 31, 2021. The Tribes have a second option to purchase an undivided 0.02% interest in Pelton/Round Butte at its discretion on or after April 1, 2041. 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 support specific capacity needs. The program also helps provide NERC-required operating reserves. As of December 31, 2015, there were 54 sites with a total capacity of 107 MW. Additional DSG projects are being pursued with goals of a total of 118 MW online by the end of 2016 and 140 MW by the end of 2018.

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 in the event that natural gas supplies are interrupted or if economic factors require its use. The storage facility is owned and operated by a local natural gas company and may be utilized to provide fuel to PW1, PW2, and Beaver. In addition, PGE is in ongoing discussions with this company concerning a new long-term natural gas storage arrangement to potentially expand their natural gas storage facilities. PGE believes that sufficient market supplies of natural gas are available to meet anticipated operations of these plants for the foreseeable future.

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 six day supply of ultra-low sulfur diesel fuel oil at the plant site as of December 31, 2015. 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, PGE has access to 41,000 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 for the foreseeable future, based on anticipated operation of the plant. 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 will provide coal for approximately half of the anticipated needs for Boardman during 2016. 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.

PGE expects to secure the balance of the needs for 2016, and beyond, by layering purchases throughout the coming year. 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 three contracts that provide PGE with firm capacity to help meet the Company’s peak loads. One contract represents 150 MW of capacity and expires in December 2016. The other two 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.

Hydro—During 2015, the Company had five contracts that provided for the purchase of power generated from hydroelectric projects with an aggregate capacity of 117 MW. One contract, which provided 58 MW, expired December 31, 2015. The remaining contracts expire 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.
- *Confederated Tribes*—PGE has a long-term agreement under which the Company purchases, at market prices, the Tribes’ interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides 162 MW of 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. During 2014, PGE entered into an agreement with the Tribes, whereby the Tribes have agreed to sell 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

In March 2014, PGE filed with the OPUC the 2013 IRP, which outlines the Company's expectations for resource needs and resource portfolio performance over the next 20 years and includes an "Action Plan," which covers the Company's proposed actions through 2017. Over that time period, PGE projects energy requirements and the energy available through its generation resources and long-term power purchase agreements to be in approximate balance. In December 2014, the OPUC acknowledged PGE's 2013 IRP with minor modifications, and the preparation and submittal of additional studies.

The Action Plan includes the following, among other items, to be undertaken through 2017:

- Seek renewal, or partial renewal, of expiring power purchase agreements for energy generated from hydroelectric projects, if available and cost-effective for customers;
- Acquire a total of 114 MWa of energy efficiency through continuation of Energy Trust of Oregon programs, with a target increase of 124 MWa, if legislation and regulation allow;
- Acquire an additional 25 MW of demand response and 23 MW of dispatchable standby generation from customers to help manage peak load conditions and other supply contingencies; and
- Perform various research and studies related to load forecast and energy efficiency projections, distributed generation resources within PGE's service territory, the viability of large-scale biomass operations, fuel supply, operational flexibility requirements and analytical tools, cost-benefit analysis of Energy Imbalance Market (EIM) participation, RPS compliance strategies, and potential impacts of compliance with United States Environmental Protection Agency's (EPA's) Clean Power Plan rules concerning reductions in carbon dioxide emissions from existing fossil fuel-fired power plants in preparation for the next IRP.

The 2013 IRP, as updated in December 2015, also incorporates PW2 and Tucannon River, both of which were placed into service in December 2014, and Carty, which is currently being constructed and targeted to be placed in service in July 2016. For additional information on Carty, 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."

In accordance with the Action Plan, PGE has evaluated its participation in an EIM. In September 2015, the Company announced plans to explore participation in the western EIM, which was launched in 2014 by the California Independent System Operator. 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 has 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 over the next two years with the Company's participation in the EIM targeted to begin in the fall of 2017.

Beyond 2017, PGE may need additional resources in order to meet the 2020 and 2025 RPS requirements and to replace energy from Boardman, which is scheduled to cease coal-fired operations at the end of 2020. Additional actions beyond 2017 may also be needed to offset expiring power purchase agreements and to integrate variable energy resources, such as wind or solar generation facilities. These actions are expected to be identified in PGE's next IRP filing with the OPUC in the latter half of 2016.

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 2015, PGE delivered approximately 22 million megawatt hours (MWh) in its balancing authority area through 1,239 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 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. Specific monetary penalties can be assessed for failure to attain required performance levels, with amounts dependent upon the extent to which actual results fail to meet such requirements.

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, cleanup, 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 in 2011 aimed at the reduction of toxic air emissions from power plants. Specifically, these mercury and air toxics standards (MATS), which became effective on April 16, 2012, for power plants are intended to reduce emissions from new and existing coal- and oil-fired electric utility steam generating units. With the installation of emissions controls, which included a Dry Sorbent Injection system, at Boardman completed in 2013, the Company believes the Boardman plant meets 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. Emissions controls in place at Colstrip allow operation within the standards necessary to meet the MATS requirements. 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 these compliance requirements.

Climate Change— The EPA has taken the lead role on climate change policy utilizing existing authority under the CAA to develop regulations. On August 3, 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 amount was 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.

States have until September 6, 2016 to submit plans to implement the rule (subject to extension). 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 for the rule's previously required September 6, 2016 deadline.

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, and the Company's ownership interest in coal-fired facilities, Boardman and Colstrip, provided, in total, approximately 64% of the Company's net generating capacity during 2015. 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.

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 have caused major operational changes to 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.

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 Federal Power Act. 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 their output 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 increase capital spending to modify the facilities to enhance fish passage and survival.

Avian Protection—Various statutes, including the Migratory Bird Treaty Act, have established civil, criminal, and administrative penalties for the unauthorized take of migratory birds. 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, referred to as Bird and Bat Conservation Strategies, for its wind generation facilities. In April 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 2016.

Hazardous Waste

PGE has a comprehensive program to comply with requirements of both federal and state regulations related to hazardous waste storage, handling, and disposal. 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 produce a by-product known as coal combustion residuals (CCR), 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. PGE has been informed by the operator of Colstrip, however, that this rule will have an effect on operations at Colstrip, which produces wet CCRs. For further information, see *"Asset Retirement Obligations"* in Note 2, Summary of Significant Accounting Policies, in the Notes to Condensed Consolidated Financial Statements.

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), commonly referred to as Superfund. The CERCLA 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 pursuant to CERCLA. The EPA has listed PGE among the more than one hundred Potentially Responsible Parties (PRPs), as PGE has historically owned or operated property near the river.

For additional information on this EPA action, see Note 18, 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 2033. 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.

In PGE’s three most recent general rate cases, overall price increases approved by the OPUC were less than the Company’s initial proposals. Under such circumstances, PGE attempts to manage its costs at levels consistent with the reduced price increases. 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. PGE files an annual AUT with an update of the Company’s forecasted net variable power costs to be reflected in customer prices (baseline NVPC). The PCAM provides a mechanism by which the Company can adjust future customer prices to reflect a portion of the difference between each year’s baseline NVPC included in customer prices 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.” The PCAM provides for a fixed deadband range of $15 million below, to $30 million above, baseline NVPC. 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’s current position as a “short” utility requires that the Company supplement 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 Standard & Poor’s Ratings Services (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 proceedings related to refunds on wholesale market transactions in the Pacific Northwest and the investigation and any resulting remediation efforts related to the Portland Harbor site, 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 18, 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 scheduled.

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 greenhouse gas 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 greenhouse gas emissions from the Company's fossil fuel-fired generation facilities. Compliance with any greenhouse gas 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 greenhouse gas 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 revenues derived from 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, which it continues to do, from retail customers for such damages and to defer any amount not utilized in the current year. During 2015, PGE fully utilized the existing reserve balance as a result of restoration costs associated with storm damage occurring between March and December 2015.

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.

PGE has a workforce with a significant number of employees approaching retirement, which could make it more difficult to maintain the workforce necessary to provide safe and reliable service to customers and meet regulatory requirements.

The Company anticipates higher averages of retirement rates over the next several years and will likely need to replace a significant number of employees in key positions. PGE’s ability to successfully implement a workforce succession plan is dependent upon the Company’s ability to employ and retain skilled professional and technical workers. Without a skilled workforce, the Company would face greater challenges in providing safe and reliable service to its customers and meeting regulatory requirements, both of which could affect operating results.

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, 2015:

Facility	Location	Net Capacity [1]	
Wholly-owned:			
Natural Gas/Oil:			
Beaver	Clatskanie, Oregon	508	MW
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		3,397	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 Federal Power Act. 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, 2015, PGE owned an electric transmission system consisting of 1,239 circuit miles as follows: 286 circuit miles of 500 kV line; 402 circuit miles of 230 kV line; and 551 miles of 115 kV line. The Company also has 26,544 circuit miles of primary and secondary 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 the Colstrip plant in Montana 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 3,105 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 for one year.

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 has filed a motion for summary judgment dismissing the lawsuits. Oral argument took place on July 27, 2015 and the Circuit Court has not yet issued its decision. Following oral argument on PGE’s motion for summary judgment, Plaintiffs moved to amend the complaints. PGE opposed the request to amend and the Court has not yet issued its decision.

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, and described the burden of proof that must be met to justify abrogation of the contracts at issue and the imposition of refunds. The orders held 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 expanded the scope of the hearing to allow parties to pursue refunds for transactions between January 1, 2000 and December 24, 2000 under Section 309 of the Federal Power Act by showing violations of a filed tariff or rate schedule or of a statutory requirement. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Refund claimants 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.

In response to the evidence and arguments presented during the remand 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 a January 2016 revised initial decision has now recommended that certain contracts by such respondent be subject to refund.

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 have not fully eliminated 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.” However, the remaining respondent subject to the revised initial decision has stated on the record that it will not pursue ripple claims. Therefore, unless the current FERC orders are overturned or modified on appeal, the Company does not believe that it will incur any material loss in connection with this matter.

Sierra Club and Montana Environmental Information Center v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and PacifiCorp, U.S. District Court for the District of Montana.

In July 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the CAA at Colstrip Steam Electric Station (CSES) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other CSES co-owners, including Talen Montana, LLC - the operator of CSES. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The Notice alleges certain violations of the CAA, and stated that the Sierra Club and MEIC would: i) request a United States District Court to impose injunctive relief and civil penalties; ii) require a beneficial environmental project in the areas affected by the alleged air pollution; and iii) seek reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees.

The Sierra Club and MEIC asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and that the owners have violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality. The Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

In March 2013, the Sierra Club and MEIC sued the CSES co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs are seeking relief that includes civil penalties and an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter.

In May 2013, the defendants filed a motion to dismiss 36 of the 39 claims in the complaint. In September 2013, the plaintiffs filed a motion for partial summary judgment regarding the appropriate method of calculating emissions increases. Also in September 2013, the plaintiffs filed an amended complaint that withdrew Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects.

In July 2014, the court denied defendants' motion to dismiss and the plaintiffs' motion for partial summary judgment. In August 2014, the plaintiffs filed a second amended complaint. The defendants' response to the second amended complaint was filed in September 2014. The second amended complaint continues to seek injunctive relief, declaratory relief, and civil penalties for alleged violations of the federal Clean Air Act. The plaintiffs state in the second amended complaint that it was filed, in part, to comply with the court's ruling on the defendants' motion to dismiss and plaintiffs' motion for partial summary judgment. Discovery in this matter is complete. The parties filed various summary judgment motions during the summer of 2015. Oral argument on those motions occurred on December 1, 2015. On or about December 31, 2015, the Magistrate Judge issued Findings and Recommendations that, if adopted by the trial court, would result in dismissal of several of the plaintiffs' claims. The case is currently set for trial on May 6, 2016.

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 January 29, 2016, there were 879 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $38.87 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
2015			
Fourth Quarter	$ 39.08	$ 34.97	$ 0.300
Third Quarter	38.00	33.09	0.300
Second Quarter	37.69	33.04	0.300
First Quarter	41.04	34.72	0.280
2014			
Fourth Quarter	$ 40.31	$ 32.07	$ 0.280
Third Quarter	34.74	31.41	0.280
Second Quarter	34.69	32.01	0.280
First Quarter	32.75	28.98	0.275

While PGE expects to pay comparable quarterly dividends on its common stock in the future, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration depends 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,				
	2015	2014	2013	2012	2011
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues, net	$ 1,898	$ 1,900	$ 1,810	$ 1,805	$ 1,813
Gross margin	65%	62%	58%	60%	58%
Income from operations [1]	$ 309	$ 293	$ 206	$ 302	$ 309
Net income [1]	172	174	104	140	147
Net income attributable to Portland General Electric Company [1]	172	175	105	141	147
Earnings per share—basic [1]	2.05	2.24	1.36	1.87	1.95
Earnings per share—diluted [1]	2.04	2.18	1.35	1.87	1.95
Dividends declared per common share	1.180	1.115	1.095	1.075	1.055
Statement of Cash Flows Data:					
Capital expenditures	598	1,007	656	303	300

(1) The year ended December 31, 2013 includes $52 million of costs expensed related to the Company's Cascade Crossing Transmission Project. For information regarding this matter, see "*Electric Utility Plant*" in Note 2, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

	As of December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 7,221	$ 7,042	$ 6,101	$ 5,670	$ 5,733
Total long-term debt	2,204	2,501	1,916	1,636	1,735
Total Portland General Electric Company shareholders' equity	2,258	1,911	1,819	1,728	1,663
Common equity ratio	50.5%	43.3%	48.7%	51.1%	48.6%

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 PGE to have a reasonable basis including, but not limited to, management's examination of historical operating trends and data contained in records and other data 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 18, 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, which may cause the Company to incur repair costs, as well as increased power costs for replacement power;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, 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 existing power and natural gas purchase agreements;
- capital market conditions, including access to capital, interest rate volatility, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, 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 or affect the operations of the Company's thermal generating 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 wholesale prices for fuels, including natural gas, coal and oil, and the impact of such changes on the Company's power costs;
- changes in the availability and price of wholesale power;
- 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;
- changes in, and compliance with, environmental and endangered species laws and policies;
- 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;
- new federal, state, and local laws that could have adverse effects on operating results;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation, transmission, and distribution facilities or information technology systems, or result in the release of confidential customer and proprietary information;
- employee workforce factors, including a significant number of employees approaching retirement, potential strikes, work stoppages, and transitions in senior management;
- political, economic, and financial market conditions;
- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;
- 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, nor can it 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 is in the process of preparing its 2016 IRP, which will address resource needs over the next 20 years. The areas of focus for the plan include, among other topics, additional resources that may be needed in order to meet the 2020 and 2025 RPS requirements and to replace energy from Boardman, which is scheduled to cease coal-fired operations at the end of 2020.

Pursuant to the Action Plan included in its 2009 IRP, PGE has undertaken to increase its generation capacity to meet growing customer demand, comply with the requirements of Oregon's RPS, limit exposure to market price volatility, and maintain system reliability. PW2 and Tucannon River were brought into service in December 2014, and Carty, which is currently being constructed with a target substantial completion date of July 2016. Management continues to evaluate potential investments to improve the reliability and efficiency of the Company's operating systems, as well as potential investments in fuel supply opportunities that would provide value to customers.

In February 2015, the Company filed a GRC with the OPUC, intended primarily to allow recovery of costs associated with the construction and operation of Carty. Customer price changes were effective January 1, 2016.

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.

Capital Requirements and Financing—During 2015, construction continued on Carty, a 440 MW natural gas-fired baseload resource in Eastern Oregon, located adjacent to the Boardman coal plant. From 2013 to December 2015, the general contractor responsible for engineering, procurement and construction of Carty was Abeinsa Abener Teyma General Partnership, an affiliate of Abengoa S.A., and affiliates of Abeinsa Abener Teyma General Partnership (Contractor). On December 18, 2015, the Company declared the Contractor in default under multiple provisions of the construction agreement (Construction Agreement) and terminated the Construction Agreement. Liberty Mutual Surety and Zurich North America (Sureties) have provided a performance bond of $145.6 million under the Construction Agreement. The Company required the Contractor to enter into the performance bond to guarantee satisfactory completion of the project in the event the Contractor failed to fulfill its obligations under 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. The Company is currently in discussions with the Sureties regarding their obligations under the performance bond. The Company believes that the Sureties will have an obligation under the performance bond to contribute funds towards the completion of Carty. However, the Sureties have not yet made a determination with respect to their obligations. Accordingly, the amount of any potential recovery of costs under the performance bond remains uncertain and cannot be reasonably estimated at this time.

On January 28, 2016, PGE received notice from the International Court of Arbitration that Abengoa S.A., the parent company of the Contractor, had submitted a Request for Arbitration in which it 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 liability of Abengoa S.A. under the terms of a guaranty in favor of PGE 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 intends to contest the arbitration claim.

As of December 31, 2015, PGE had $424 million, including $41 million of AFDC, included in CWIP for the project. Remaining major milestones to complete the project consist of test firing the plant, commissioning, and substantial completion. As a result of the termination of the Construction Agreement, the transition to a new construction team, and related matters, additional costs are expected to be incurred to complete construction of Carty, including, among other things, costs related to determining the remaining scope of construction, re-performing work performed by the Contractor that did not meet specifications, completing an inventory of materials either on-site, ordered, or in transit, preparing work plans for contractors, identifying new contractors, negotiating contracts, procuring additional materials, completing unfinished construction, and removing liens on the property. The Company currently estimates that the total capital expenditures for Carty, including AFDC, will be approximately $620 million to $655 million, before considering any amount that may be received from the Sureties pursuant to the performance bond. The foregoing circumstances have also caused a delay in the expected completion of Carty, with the Company currently targeting an in service date in July 2016. However, due to the transition to a new construction team, uncertainties relating to the work necessary to complete construction, and related matters, the costs and completion date for Carty could vary from the Company's current estimates.

Increased costs and delay of the targeted in service date could also impact the timing and amount of the Company's recovery of Carty costs in customer prices. On November 3, 2015, the OPUC issued an order approving settlements reached in PGE's 2016 GRC filing. The order authorized the inclusion in customer prices of capital costs for Carty of up to $514 million, including AFDC, as well as its operating costs, at such time the plant is placed in service, provided that occurs by July 31, 2016. If the costs incurred by PGE to complete Carty, less any amounts received from the Sureties, exceeds the $514 million amount approved by the OPUC, the Company would seek recovery of the excess amount in customer prices in a subsequent GRC proceeding. However, there is no assurance that such recovery would be granted by the OPUC. If the Carty in service date were to be delayed beyond July 31, 2016, PGE would pursue one or more alternative avenues to obtain OPUC approval for the inclusion of Carty costs in customer prices. Under such circumstance, the Company might not be able to recover some or all of the net revenue requirements for Carty from the date Carty is placed into service until the time when new approved customer prices are effective for Carty.

PGE's capital requirements amounted to $553 million for 2015, with $140 million related to the construction of Carty, excluding AFDC. The remainder of the 2015 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 2015, the combination of cash from operations in the amount of $517 million, proceeds from the issuance of shares pursuant to an equity forward sale agreement (EFSA) in the amount of $271 million, and proceeds from issuances of FMBs and commercial paper in the amount of $151 million funded the Company's capital requirements. For information concerning the EFSA, see Note 12, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Capital requirements in 2016 are expected to approximate $623 million, which includes the high end of the estimated range of capital expenditures to complete Carty of $174 million to $209 million, excluding AFDC. PGE plans to fund the 2016 capital requirements with cash from operations during 2016, which is expected to range from $490 million to $530 million and the issuance of short- and long-term debt securities. 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—On February 12, 2015, PGE filed with the OPUC a 2016 GRC, which is based on a 2016 test year and includes costs related to Carty. In August 2015, PGE, OPUC Staff, and other parties settled all issues in the case. In November 2015, PGE filed final updated power cost and retail load forecasts. As revised, the expected net increase in annual revenue requirements of $12 million represents an increase of approximately 0.7% in overall customer prices and reflects:

- A capital structure of 50% debt and 50% equity;
- A return on equity of 9.6%;

- A cost of capital of 7.51%; and
- An average rate base of $4.4 billion.

The net annual revenue requirement increase will be effective in two phases. A $44 million decrease, representing a 2.5% decrease in customer prices effective January 1, 2016, will consist of a reduction in base business costs of $15 million and a decrease of $30 million related to the amortization and recognition of certain customer credits through supplemental tariffs. A $57 million annualized revenue increase will be effective when Carty is placed in service, provided that occurs by July 31, 2016. The increase will consist of an $85 million annualized increase related to the cost recovery of Carty and a $28 million annualized decrease related to the amortization of certain customer credits through supplemental tariffs. If Carty is not completed and in service by July 31, 2016, PGE will need to file a new ratemaking request seeking the inclusion of the Carty costs in customer prices. For further discussion on Carty, see *"Capital and Financing"* in this Overview section of Item 7.

On January 1, 2015, new customer prices went into effect pursuant to the OPUC order issued on PGE's 2015 GRC, which was based on a 2015 test year and included forecasted retail energy deliveries assuming average weather conditions. The OPUC authorized a $15 million increase in annual revenues, representing an approximate 1% overall increase in customer prices. The increase included recovery of costs related to PW2 and Tucannon River. In addition, the order approved a capital structure of 50% debt and 50% equity, a return on equity of 9.68%, a cost of capital of 7.56%, and an average rate base of $3.8 billion.

Pursuant to the 2015 GRC order, a forecast of capital expenditures for PW2 of $323 million and Tucannon River of $525 million was used to set customers prices. The order provided for a deferral and refund to customers to the extent that total capital expenditures were less than those used to set customer prices. The Company deferred $3 million in 2015 for the revenue requirement to be refunded to customers for PW2, as actual capital expenditures were less than the amounts used for setting prices. This amount is currently being refunded to customers over a one year period that began January 1, 2016. For further information regarding actual costs recorded as of December 31, 2014, see "Capital Requirements and Financing" in this Overview, above.

In December 2013, the OPUC issued an order on PGE's 2014 GRC, which was based on a 2014 test year. The OPUC authorized a $61 million increase in annual revenues, representing an approximate 4% overall increase in customer prices, which became effective January 1, 2014. The order reflects a capital structure of 50% debt and 50% equity, a return on equity of 9.75%, a cost of capital of 7.65%, and a rate base of approximately $3.1 billion.

The general rate case filings, 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. PGE is a winter-peaking utility that typically experiences its highest retail energy demand during the winter heating season, although a slightly lower peak occurs in the summer that generally results from air conditioning demand. 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 2015, retail energy deliveries increased 0.6% from 2014, which was driven by an increase in industrial energy deliveries partially offset by a decrease in residential energy deliveries. For 2015 and 2014, the average number of retail customers and deliveries, by customer type, were as follows:

	2015		2014		Increase/ (Decrease) in Energy Deliveries
	Average Number of Customers	**Energy Deliveries ***	**Average Number of Customers**	**Energy Deliveries ***	
Residential	742,467	7,325	735,502	7,462	(1.8)%
Commercial	105,802	7,511	105,231	7,494	0.2
Industrial	255	4,546	260	4,310	5.5
Total	848,524	19,382	840,993	19,266	0.6 %

* In thousands of MWh, including deliveries to those commercial and industrial customers that purchase their energy from ESSs.

The increase in industrial energy deliveries was driven by increased demand from the high tech industry, paper manufacturing, and food manufacturing sectors, partially offset by decreased demand from metal manufacturing customers. The relatively small change in commercial deliveries was primarily the result of an increase in deliveries to irrigation and service sector customers, mostly offset by lower deliveries to other commercial sectors.

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. As a result, minimal earnings impact is expected in 2016.

The decline in demand from residential customers is largely attributable to warmer weather conditions during the 2015 heating season relative to 2014. According to the National Oceanic and Atmospheric Administration's climatological rankings, the 3-month period of January through March 2015, was the warmest on record for the state of Oregon. Residential energy deliveries in the first quarter of 2015 were 11.2% lower than the same period of 2014. The full year 2015, taken as a whole, was also 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 2015 (an indication of the extent to which customers are likely to use, or have used, electricity for heating) were 19% lower than the 15-year average, and 9% below total heating degree days in 2014.

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 that projected in the Company's most recent approved general rate case. Results for the past three years are summarized as follows:

- For 2015, PGE recorded an estimated refund of $9 million as weather adjusted energy use per customer was greater than that estimated and approved in the Company's 2015 GRC. A final determination of the 2015 estimate will be made by the OPUC through a public filing and review in 2016. Any resulting refund to customers is expected to begin January 1, 2017.
- For 2014, the Company recorded an estimated refund of $7 million as weather adjusted energy use per customer was greater than that estimated and approved in PGE's 2014 General Rate Case (2014 GRC). In addition, the Company recorded in 2014 a $2 million collection related to 2013 resulting from the OPUC's

review. Amortization of the net $5 million amount began in January 2016 following a final determination of the amount through a public filing and review by the OPUC during 2015.

- For 2013, PGE recorded an estimated collection of $3 million. In addition, the Company recorded in 2013 a $2 million collection related to 2012 resulting from the OPUC's review. A final determination of the 2013 estimate was made by the OPUC through a public filing and review in 2014, which resulted in a $5 million collection for 2013.

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%, 92%, and 89% for the years ended December 31, 2015, 2014, and 2013, respectively, with the availability of Colstrip, which PGE does not operate, approximating 93%, 83%, and 66%, respectively.

Beginning in July 2013, the Company experienced three unplanned plant outages with Boardman off-line for July 2013, Coyote Springs off-line for September through November 2013, and Colstrip Unit 4 off-line for July 2013 through January 2014. As a result of these unplanned outages, the Company incurred incremental replacement power costs of approximately $2 million in 2014 and $17 million in 2013.

During the year ended December 31, 2015, the Company's generating plants provided approximately 65% of its retail load requirement compared to 58% in 2014 and 54% in 2013. The increase in 2015 reflects the combined impact of the addition of PW2 and Tucannon River, and lower natural gas prices resulting in PGE's ability to economically generate a greater portion of its total system load. As a result, in 2015, the Company reduced reliance on purchased power by 11% from 2014 levels. The lower relative volume of power generated to meet the Company's retail load requirement during 2013 resulted primarily from the above mentioned outages.

PGE has contracted with a local natural gas company to potentially expand their gas storage facilities near Mist, Oregon, which PGE will utilize to serve its gas-fired electric power generation facilities at PW1, PW2, and Beaver. Under the contract, PGE has authorized the gas company to spend up to $8 million for work associated with preliminary engineering, permitting, geotechnical investigations, and land acquisition. The project has a potential in service date of 2018 or 2019, however, in the event the project does not go forward there are certain situations in which PGE is liable to reimburse the gas company for the costs incurred on behalf of PGE. This project is subject to PGE's final approval of estimated projected costs and a notice to proceed, as well as the local gas company's receipt of permits and certain land rights needed for the project.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects decreased 9% in 2015 compared to 2014, primarily due to less favorable hydro conditions in 2015. These resources provided 16% of the Company's retail load requirement for 2015, compared with 18% for 2014 and 17% for 2013. Energy received from these sources fell short of projections (or "normal") included in the Company's AUT by approximately 7% in 2015, and exceeded projections by 2% in 2014 and 1% in 2013. 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. Although 2015 regional hydro conditions were well below average, based on recent forecasts, energy from hydro resources is expected to be slightly below avera ge for 2016. See *"Purchased power and fuel"* in the 2015 Compared to 2014 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 is projected annually in the AUT and through 2013, for Biglow Canyon, was based on wind studies completed in connection with the permitting process of the wind farm. For 2014 and beyond, the projection included in the AUT is 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 the wind studies. 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 15% in 2015, 9% in 2014 and 15% in 2013. 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) 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 for 2015, 2014 and 2013:

- For 2015, actual NVPC, as calculated for regulatory purposes under the PCAM, was $3 million below the baseline NVPC, which is 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 will be made by the OPUC through a public filing and review in 2016.
- For 2014, actual NVPC was below baseline NVPC by $7 million, which is 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 2013, actual NVPC was above baseline NVPC by $11 million, and which was within the established deadband range. Accordingly, no estimated collection from customers was recorded as of December 31, 2013. A final determination regarding the 2013 PCAM results was made by the OPUC through a public filing and review in 2014, which confirmed no collection from customers pursuant to the PCAM for 2013.

For further information concerning the PCAM, see *Power Costs* under "*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 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 at Portland Harbor; and
- Claims alleging that PGE and the other co-owners of the Colstrip Steam Electric Station violated the CAA, the plant's air quality operating permit and various other environmental regulations.

For additional information regarding the above and other matters, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

On August 3, 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 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 “Environmental Matters” in Item 1.—“Business.”

The following discussion highlights certain regulatory items, which have impacted, or will 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.

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 based on lower forecasted power costs. 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.

PGE’s forecast of power costs for 2016 was approved by the OPUC with an expected reduction in annual revenues of approximately $31 million based on lower forecasted power costs. This amount was included in the expected net annual revenue requirement increase of $12 million the OPUC authorized under the Company’s 2016 GRC. For further information, see *“General Rate Cases”* in this Overview section, above.

In June 2015, the Company submitted the 2014 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 October 2015, the OPUC issued an order to such effect. For further information, see *“Power Operations”* in the Operating Activities section of this Overview, above.

Renewable Resource Costs—Pursuant to a renewable adjustment clause (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 beginning January 1, 2016. On October 2, 2015, the OPUC issued an order approving the deferral of costs associated with the facility.

PGE submitted a RAC filing to the OPUC in 2014 anticipating that Tucannon River would be placed into service before the end of 2014. The Company utilized the RAC to record the revenue requirement, which was estimated to be approximately $1 million, for the period from December 15, 2014 when the facility was placed into service, until December 31, 2014. Because Tucannon River was included in the 2015 GRC, PGE proposed to provide the final actual deferred revenue requirement to the OPUC in the first quarter of 2015. On April 15, 2015, the OPUC issued an order approving the deferral amount to be amortized and collected from customers in prices during the period July 1, 2015 through December 31, 2015.

Decoupling Mechanism—The decoupling mechanism, which the OPUC has 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. 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 refund of $9 million during the year ended December 31, 2015, which resulted from variances between actual weather adjusted use per customer and that projected in the 2015 GRC. Any refund is expected to occur over a one-year period, which will begin January 1, 2017. See *"Customers and Demand"* in this *Overview* section for further information on the decoupling mechanism.

Capital deferral—In the 2011 General Rate Case (2011 GRC), the OPUC authorized the Company to defer the costs associated with four capital projects that were not completed at the time the 2011 GRC was approved. In 2012 and 2013, PGE deferred such costs and recorded a regulatory asset for potential future recovery in customer prices with an offsetting credit to Depreciation and amortization expense. In 2015, the Company amortized the balance of the deferred costs and interest associated with these projects totaling $19 million, with recovery of such amounts included in customer prices over a one year period ending December 31, 2015. As a result of this tariff expiration, the Company's revenues and depreciation expense will decrease in 2016, with no impact on earnings. Beginning January 1, 2014, the costs of these projects were reflected in the Company's rate base.

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 for the years presented (dollars in millions):

	Years Ended December 31,					
	2015		2014		2013	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net	$ 1,898	100%	$ 1,900	100%	$ 1,810	100%
Purchased power and fuel	661	35	713	38	757	42
Gross margin	1,237	65	1,187	62	1,053	58
Other operating expenses:						
Generation, transmission and distribution	266	14	257	13	225	12
Cascade Crossing transmission project	—	—	—	—	52	3
Administrative and other	241	13	227	12	219	12
Depreciation and amortization	305	16	301	16	248	14
Taxes other than income taxes	116	6	109	6	103	6
Total other operating expenses	928	49	894	47	847	47
Income from operations	309	16	293	15	206	11
Interest expense, net *	114	6	96	5	101	5
Other income:						
Allowance for equity funds used during construction	21	1	37	2	13	1
Miscellaneous income, net	1	—	1	—	7	—
Other income, net	22	1	38	2	20	1
Income before income taxes	217	11	235	12	125	7
Income tax expense	45	2	61	3	21	1
Net income	172	9	174	9	104	6
Less: net loss attributable to noncontrolling interests	—	—	(1)	—	(1)	—
Net income attributable to Portland General Electric Company	$ 172	9%	$ 175	9%	$ 105	6%

* Includes an allowance for borrowed funds used during construction of $13 million in 2015, $22 million in 2014, and $7 million in 2013.

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

	Years Ended December 31,					
	2015		2014		2013	
Revenues[1] (dollars in millions):						
Retail:						
Residential	$ 895	47 %	$ 893	47%	$ 861	48%
Commercial	662	35	657	34	619	34
Industrial	228	12	221	12	217	12
Subtotal	1,785	94	1,771	93	1,697	94
Other accrued (deferred) revenues, net	(10)	(1)	(8)	—	(5)	—
Total retail revenues	1,775	93	1,763	93	1,692	94
Wholesale revenues	88	5	95	5	80	4
Other operating revenues	35	2	42	2	38	2
Total revenues	$ 1,898	100 %	$ 1,900	100%	$ 1,810	100%
Energy deliveries[2] (MWh in thousands):						
Retail:						
Residential	7,325	33 %	7,462	34%	7,702	35%
Commercial	7,511	34	7,494	34	7,441	34
Industrial	4,546	21	4,310	20	4,276	20
Total retail energy deliveries	19,382	88	19,266	88	19,419	89
Wholesale energy deliveries	2,560	12	2,520	12	2,353	11
Total energy deliveries	21,942	100 %	21,786	100%	21,772	100%
Average number of retail customers:						
Residential	742,467	88 %	735,502	87%	728,481	87%
Commercial	105,802	12	105,231	13	104,385	13
Industrial	255	—	260	—	263	—
Total	848,524	100 %	840,993	100%	833,129	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.

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

	Years Ended December 31,					
	2015		2014		2013	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Coal	4,128	19%	4,466	21%	4,070	19%
Natural gas	4,783	22	3,429	16	3,375	16
Total thermal	8,911	41	7,895	37	7,445	35
Hydro	1,453	7	1,750	8	1,646	8
Wind	1,788	8	1,172	6	1,200	5
Total generation	12,152	56	10,817	51	10,291	48
Purchased power:						
Term	4,379	21	5,926	28	6,472	31
Hydro	1,572	7	1,568	7	1,629	8
Wind	303	2	317	2	311	1
Spot	2,985	14	2,626	12	2,547	12
Total purchased power	9,239	44	10,437	49	10,959	52
Total system load	21,391	100%	21,254	100%	21,250	100%
Less: wholesale sales	(2,560)		(2,520)		(2,353)	
Retail load requirement	18,831		18,734		18,897	

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 to $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 causing energy deliveries to be 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, which 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 brought on line in December 2014, 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 from the completion of construction of the two new generating facilities, which, in part, contributed to increased interest expense in 2015. 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.

Net income attributable to Portland General Electric Company for the year ended December 31, 2014 was $175 million, or $2.18 per diluted share, compared to $105 million, or $1.35 per diluted share, for the year ended December 31, 2013. The $70 million, or 67%, increase in net income was primarily driven by higher average retail prices resulting from the January 1, 2014 price increase authorized by the OPUC in the Company's 2014 GRC, lower net variable power costs, an increase in AFDC resulting from a higher average CWIP balance, and the charge to expense of $52 million of previously capitalized costs related to Cascade Crossing Transmission Project in the second quarter of 2013. A decrease of 0.8% in retail energy deliveries driven by a decline in residential energy deliveries, higher operating and maintenance expenses, combined with an increase in the Company's effective tax rate to 26.0% for 2014 from 16.8% for 2013 partially offset the increases to net income.

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. See *"Customers and Demand"* in the Overview section of this Item 7. for further information on customer demand; 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 the 2014 total. 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. PGE projects that retail energy deliveries for 2016 will be approximately 1% higher than 2015 weather adjusted levels, after allowance for energy efficiency and conservation efforts, and the removal of one large paper customer that ceased operations in late 2015.

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 2015, the $7 million, or 7%, decrease in wholesale revenues from 2014 consisted of $8 million related to 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 were comparable in 2015 to 2014.

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 2015, Purchased power and fuel expense decreased $52 million, or 7%, from 2014, which was 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% for 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. Based on recent forecasts of regional hydro conditions in 2016, energy from hydro resources is expected to be slightly below normal, although above 2015 levels.

The following table presents the forecast of the April-to-September 2016 runoff (issued February 7, 2016) compared to the actual runoffs for 2015 and 2014:

	Runoff as a Percent of Normal *		
Location	**2016 Forecast**	**2015 Actual**	**2014 Actual**
Columbia River at The Dalles, Oregon	94%	69%	108%
Mid-Columbia River at Grand Coulee, Washington	94	77	110
Clackamas River at Estacada, Oregon	96	53	97
Deschutes River at Moody, Oregon	94	85	98

* 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.

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, which consists of Purchased power and fuel expense net of Wholesale revenues, 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 the 2015 baseline NVPC. In 2014, NVPC was $7 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 $9 million, or 4%, in 2015 compared with 2014. The increase was driven by the combination of $9 million in higher costs due to the addition of PW2 and Tucannon River, $3 million higher information technology expenses, $2 million of 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 with 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 with $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 to 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 production tax credits 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.

2014 Compared to 2013

Revenues increased $90 million, or 5%, in 2014 compared with 2013 as a result of the items discussed below.

Total retail revenues increased $71 million, or 4%, in 2014 compared with 2013, primarily due to the net effect of the following:

- A $60 million increase related to higher average retail prices resulting from the January 1, 2014 price increase authorized by the OPUC in the Company's 2014 GRC;
- A $20 million increase related to an increase in the average retail price for the collection of deferred costs related to four capital projects beginning January 1, 2014 (offset in Depreciation and amortization expense);
- A $9 million increase as a result of an industrial customer refund recorded in the second quarter of 2013 (reflected in Other retail revenues, net) related to cumulative over-billings that occurred over a period of several years as a result of a meter configuration error; and
- A $5 million increase related to various items, including other supplemental tariff changes; partially offset by
- A $13 million decrease related to a 0.8% decline in retail energy deliveries, consisting of a decrease of 3.1% in residential partially offset by increases of 0.7% and 0.8% in commercial and industrial, respectively; and
- A $10 million decrease related to the decoupling mechanism, with an overall estimated refund of $5 million recorded in 2014 compared with an overall estimated collection of $5 million recorded in 2013.

Total heating degree-days in 2014 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 2013. Total cooling degree days in 2014 exceeded the 15-year average and 2013 total cooling degree-days. The following table presents the number of heating and cooling degree-days in 2014 and 2013, along with the 15-year averages:

	Heating Degree-Days			Cooling Degree-Days		
	2014	2013	15-Year Average	2014	2013	15-Year Average
1st quarter	1,891	1,902	1,864	—	—	—
2nd quarter	530	593	713	57	82	70
3rd quarter	18	90	85	579	457	382
4th quarter	1,355	1,801	1,602	17	—	1

Total	3,794	4,386	4,264	653	539	453
Increase (decrease) from the 15-year average	(11)%	3%		44%	19%	

On a weather adjusted basis, retail energy deliveries in 2014 were 0.3% below 2013, with energy deliveries to residential customers decreasing by 1.9% and energy deliveries to commercial and industrial customers each increasing 0.8%.

Wholesale revenues in 2014 increased $15 million, or 19%, from 2013, with such increase comprised of $9 million related to an 11% increase in the average wholesale price and $6 million related to a 7% increase in wholesale sales volume.

Other operating revenues increased $4 million, or 11%, in 2014 from 2013, primarily due to higher sales of excess transmission capacity and services, as well as an increase in pole contact rentals. The increase was partially offset by a $6 million decrease in gains on the sale of excess natural gas not needed for operations.

Purchased power and fuel expense in 2014 decreased by $44 million, or 6%, from 2013, which was driven by a 6% decline in the average variable power cost per MWh to $33.54 in 2014 from $35.61 in 2013. The decrease was driven by a decline in the Company's cost of natural gas to fuel natural gas-fired plants in 2014 compared with 2013, combined with the need for higher-cost replacement power in 2013 resulting from thermal plant outages.

Energy received from both PGE-owned hydroelectric projects and from mid-Columbia projects combined for 2014 was comparable with 2013, contributing 18% of the Company's retail load requirement for 2014 and 17% for 2013. Total hydroelectric energy received exceeded that projected in PGE's AUT by approximately 2% for 2014 and 1% for 2013.

The following table presents the actual of the April-to-September runoff for 2014 and 2013:

	Runoff as a Percent of Normal *	
Location	**2014 Actual**	**2013 Actual**
Columbia River at The Dalles, Oregon	108%	100%
Mid-Columbia River at Grand Coulee, Washington	110	108
Clackamas River at Estacada, Oregon	97	102
Deschutes River at Moody, Oregon	98	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.

Energy received from PGE-owned wind generating resources in 2014 decreased 2% from 2013, and represented 6% of the Company's retail load requirement in each of those years. Energy received from wind generating resources fell short of projections included in the Company's AUT by approximately 9% in 2014 compared with 15% in 2013.

Actual NVPC decreased $59 million for 2014 compared with 2013. The decrease was largely due to a 6% decline in the average variable power cost per MWh, combined with an 11% increase in the average price per MWh of wholesale power sales and a 7% increase in the volume of wholesale power sales. For 2014, actual NVPC was $7 million below baseline NVPC, compared with $11 million above for 2013.

Generation, transmission, and distribution expense increased $32 million, or 14%, in 2014 compared with 2013. Storm related and service restoration costs were collectively $10 million higher primarily related to the Company's service territory experiencing three major wind storms during the fourth quarter of 2014 ($5 million of which was offset by increased revenues utilizing the storm recovery mechanism). In addition, operating costs increased $7 million as a result of the Company's ownership interest in Boardman increasing to 80% from 65% on December 31, 2013, and maintenance and overhaul expenses at PGE's generation facilities were $6 million greater than in 2013. Other distribution expenses were up $7 million, including $4 million of substation related expense, other generation expenses increased $3 million, and other transmission expenses increased $1 million. Partially offsetting these increases was a $3 million relative decrease in 2014 due to expense taken in 2013 related to the Company's benchmark bid for renewable resources pursuant to the 2009 IRP.

Cascade Crossing transmission project reflects $52 million of costs expensed in the second quarter of 2013, which were previously recorded as CWIP. For additional information, see "*Electric Utility Plant*" in Note 2, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Administrative and other expense increased $8 million, or 4%, in 2014 compared with 2013. The increase was due in large part to $5 million more incentive compensation expense recorded in 2014 than in 2013 due to the higher net income in 2014. Additionally, customer service expenses, reflecting higher information technology costs, were $4 million higher in 2014, while medical premiums, rent, and other items combined to increase expense $5 million. Partially offsetting these increases were a $3 million reduction in injuries and damages expense resulting from insurance recoveries related to prior year claims and a $3 million reduction in pension expense due to higher discount rates.

Depreciation and amortization expense in 2014 increased $53 million, or 21%, compared with 2013. In 2013, PGE deferred, for future recovery, $17 million of costs related to four capital projects as authorized in the Company's 2011 GRC and in 2014 recorded $16 million of amortization expense related to the actual recovery of these costs (offset in Retail revenues). The addition of capital assets also contributed to an increase of $16 million in Depreciation and amortization expense year over year.

Taxes other than income taxes expense increased $6 million, or 6%, in 2014 compared with 2013, primarily due to higher property taxes, resulting from increases in appraised property values, along with an increase in payroll taxes.

Interest expense decreased $5 million, or 5%, in 2014 compared to 2013, as a $16 million reduction resulted from the higher allowance for borrowed funds used during construction due to the higher average CWIP balance, partially offset by an increase in interest expense from the higher average balance of debt outstanding in 2014, resulting from the construction of PW2, Carty, and Tucannon River.

Other income, net was $38 million in 2014 compared to $20 million in 2013. The increase was primarily due to a $24 million increase in the allowance for equity funds used during construction from the higher average CWIP balance, partially offset by a decrease in earnings from the Non-qualified benefit plan trust assets.

Income tax expense increased $40 million, or 190%, in 2014 compared with 2013, primarily due to the increase in pre-tax income in 2014 compared to 2013, which was driven in part by the charges to expense in 2013 related to Cascade Crossing and an industrial customer refund. The effective tax rate increased to 26.0% for 2014 from 16.8% for 2013 due primarily to the increase in pre-tax income and the smaller relative percentage thereof represented by federal and state tax credits, partially offset by the effect of increased AFDC equity.

Liquidity and Capital Resources

Discussions, forward-looking statements, and projections in this section, and similar statements in other parts of the Form 10-K, are subject to PGE's assumptions regarding the availability and cost of capital. See "Current 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 scheduled." in Item 1A.—"Risk Factors."

Capital Requirements

The following table presents actual capital expenditures and debt maturities for 2015 and projected capital expenditures and future debt maturities for 2016 through 2020 (in millions, excluding AFDC):

	Years Ending December 31,					
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Ongoing capital expenditures	$ 391	$ 402	$ 338	$ 303	$ 280	$ 285
Carty [1]	140	209	—	—	—	—
Hydro licensing and construction	22	12	4	2	1	15
Total capital expenditures	$ 553 [2]	$ 623	$ 342	$ 305	$ 281	$ 300
Long-term debt maturities	$ 67	$ —	$ 58	$ 75	$ 300	$ —

(1) Amount shown for 2016 reflects the high end of the estimated range of capital expenditures to complete Carty, which is $174 million to $209 million, before considering any amount that may be received from the Sureties pursuant to the performance bond.
(2) 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 of upgrades to and replacement of transmission, distribution, and generation infrastructure as well as new customer connections. For the years 2016 through 2018, approximately $110 million relates to the implementation of the Company's new customer information and meter data management systems. In addition, $30 million was incurred in 2015 for the completion of construction of PW2, a 220 MW natural gas-fired flexible capacity resource located adjacent to PW1 and Beaver near Clatskanie, Oregon, and Tucannon River, a 267 MW nameplate capacity wind farm, consisting of 116 turbines each with a generating capacity of 2.3 MWs, located in southeastern Washington, both of which were placed in service in December 2014.

Carty—Carty is a 440 MW natural gas-fired baseload resource in Eastern Oregon, located adjacent to the Boardman coal plant, and is targeted to be placed in service in July 2016. Estimated expenditures for 2016 could range from $174 million to $209 million, excluding AFDC. As of December 31, 2015, $424 million, including $41 million of AFDC, is included in CWIP for Carty. Estimated total expenditures for Carty would be offset by any amounts received from the Sureties pursuant to the performance bond. For additional information, see "*Capital Requirements and Financing*" in the Overview section in Item 7.-"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Hydro licensing and construction—PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the Federal Power Act. The licenses for the hydroelectric projects expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055. Capital spending requirements reflected in the preceding table relate primarily to modifications to the Company's various hydro facilities to enhance fish passage and survival, as required by conditions contained in the operating licenses.

Long-term debt maturities—This line in the table above includes $67 million of FMBs in 2015 that were previously presented in 2016. Such FMBs had an original maturity date in 2016, but were repaid in 2015.

Liquidity

PGE's access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company's 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, information technology systems, as well as 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,		
	2015	**2014**	**2013**
Cash and cash equivalents, beginning of year	$ 127	$ 107	$ 12
Net cash provided by (used in):			
Operating activities	517	518	544
Investing activities	(522)	(994)	(692)
Financing activities	(118)	496	243
Net change in cash and cash equivalents	(123)	20	95
Cash and cash equivalents, end of year	$ 4	$ 127	$ 107

2015 Compared to 2014

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 $1 million decrease in cash flows from operating activities in 2015 compared to 2014 was largely due to 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. These decreases were partially offset by an increase to Net income, net of non-cash items.

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 2016 will range from $315 million to $325 million. Combined with all other sources, cash provided by operations in 2016 is estimated to range from $490 million to $530 million. This estimate anticipates a $23 million return of margin deposits held by brokers as of December 31, 2015, which is based on both the timing of contract settlements and projected energy prices. The remainder of the estimated cash flows from operations in 2016 is expected from normal operating activities.

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 $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."

The Company plans for approximately $623 million of capital expenditures in 2016 related to upgrades to and replacement of generation, transmission, and distribution infrastructure. The planned amount reflects the high end of the estimated range of capital expenditures to complete Carty in 2016, which is $174 million to $209 million, excluding AFDC. PGE plans to fund the 2016 capital expenditures with cash from operations during 2016, as discussed above, as well as with the issuance of short- and long-term debt securities. These amounts do not include any estimated amounts to be received from the Sureties pursuant to the performance bond related to the Carty project, which cannot be reasonably estimated at this time. 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 2015, cash used in financing activities consisted of repayments of long-term debt of $442 million and 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.

2014 Compared to 2013

Cash Flows from Operating Activities—The $26 million decrease in cash flows from operating activities in 2014 compared to 2013 was largely due to a decrease in the net change in working capital items and a $38 million decrease in the amount received related to the settlement of a legal matter concerning costs associated with the operation of the ISFSI. Such amounts were transferred into the Nuclear decommissioning trust, and consequently are also reflected as outflows of cash for investing activities. These decreases were partially offset by an increase to Net income, net of non-cash items, and an increase in cash received from the Bonneville Power Administration to be returned to customers pursuant to the Residential Exchange Program.

Cash Flows from Investing Activities—The $302 million increase in net cash used in investing activities in 2014 compared to 2013 was primarily due to a $351 million increase in capital expenditures, largely due to the construction of three new generation projects (PW2, Carty, and Tucannon River), partially offset by a decrease in contributions to the Nuclear decommissioning trust. For additional information regarding the contributions to 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 2014, 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. During 2013, net cash provided by financing activities consisted of net proceeds received from the issuances of common stock in the amount of $67 million and FMBs in the aggregate amount of $377 million, partially offset by the repayment of FMBs of $100 million and commercial paper of $17 million, and payment of dividends of $84 million.

Dividends on Common Stock

The following table presents common stock dividends declared in 2015:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 18, 2015	March 25, 2015	April 15, 2015	$ 0.280
May 6, 2015	June 25, 2015	July 15, 2015	0.300
July 23, 2015	September 25, 2015	October 15, 2015	0.300
October 22, 2015	December 28, 2015	January 15, 2016	0.300

While the Company expects to pay comparable quarterly dividends on its common stock in the future, 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.

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, 2015, PGE had posted approximately $96 million of collateral with these counterparties, consisting of $33 million in cash and $63 million in bank letters of credit, $14 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, 2015, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $102 million and decreases to approximately $40 million by December 31, 2016 and $17 million by December 31, 2017. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $197 million and decreases to approximately $83 million by December 31, 2016 and $57 million by December 31, 2017.

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 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, 2015, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $867 million 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, 2015, the Company’s debt to total capital ratio, as calculated under the credit agreements, was 49.5%.

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. However, the Company’s ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions. For 2016, PGE expects to fund estimated capital requirements with cash from operations, the issuance of debt securities of approximately $300 million, a portion of which was issued in January 2016, as described below in *“Long-term Debt,”* and the issuance of commercial paper, as needed. The actual timing and amount of any such issuances of debt and 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, 2015, PGE had a $500 million 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 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 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 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, 2015, PGE had $6 million of commercial paper outstanding, and no borrowings or letters of credit issued. As of December 31, 2015, the aggregate unused available credit capacity under the revolving credit facility was $494 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 $108 million were outstanding as of December 31, 2015.

Long-term Debt. During 2015, PGE issued a total of $145 million of FMBs and repaid $137 million FMBs and $305 million long-term bank loans as follows:

- In January, issued $75 million of 3.55% Series FMBs due 2030; and repaid $70 million of 3.46% Series FMBs;
- In February, repaid $50 million of long-term bank loans;
- In May, issued $70 million of 3.5% Series FMBs due 2035 and repaid $67 million of 6.80% Series FMBs, due January 2016;
- In June, repaid $200 million of long-term bank loans; and
- In July, repaid the remaining outstanding balance of long-term debt bank loans in the amount of $55 million.

During 2014, PGE obtained four term loans pursuant to a credit agreement in an aggregate principal amount of $305 million. The credit agreement was set to expire October 30, 2015, at which time any amounts outstanding under the term loans were to become due and payable. The Company fully repaid these term loans early with the final payment made in July 2015.

As of December 31, 2015, total long-term debt outstanding was $2,204 million, with no scheduled maturities in 2016. In addition, PGE has the option to remarket through 2033 the $21 million of Pollution Control Revenue Bonds held by the Company.

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.

Equity. In connection with PGE's public offering of 11,100,000 shares of its common stock in 2013, the Company entered into an EFSA. During the second quarter 2015, PGE physically settled in full the EFSA by issuing 10,400,000 shares of PGE common stock in exchange for net proceeds of $271 million. For additional information on the EFSA, see Note 12, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

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 50.5% and 43.3% as of December 31, 2015 and 2014, respectively.

Contractual Obligations and Commercial Commitments

The following table presents PGE's contractual obligations as of December 31, 2015 (in millions):

	2016	2017	2018	2019	2020	There-after	Total
Long-term debt	$ —	$ 58	$ 75	$ 300	$ —	$ 1,771	$ 2,204
Interest on long-term debt (1)	117	115	111	97	92	1,530	2,062
Capital and other purchase commitments	85	2	2	2	9	27	127
Purchased power and fuel:							
Electricity purchases	226	204	147	150	190	852	1,769
Capacity contracts	26	6	6	5	4	16	63
Public Utility Districts	6	5	5	1	1	12	30
Natural gas	67	41	38	37	32	221	436
Coal and transportation	14	11	5	5	—	—	35
Pension Plan Contributions (2)	—	6	22	22	21	—	71
Operating leases	10	10	9	7	6	180	222
Total	$ 551	$ 458	$ 420	$ 626	$ 355	$ 4,609	$ 7,019

(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, 2015.
(2) Contributions beyond 2020 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 outstanding debt. 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

In 2013, PGE entered into an EFSA in connection with a registered public offering of its common stock. The Company settled the EFSA with issuance of PGE common stock, for net cash proceeds during 2015. For additional information on the EFSA, see Note 12, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

PGE has no other 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 2015 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, and generation operations. 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 thermal, hydroelectric, and wind 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, 2015 that are expected to settle in each respective year (in millions):

	2016	2017	2018	2019	2020	Thereafter	Total
Commodity contracts:							
Electricity	$ 29	$ 8	$ 7	$ 7	$ 6	$ 69	$ 126
Natural gas	91	50	12	2	—	—	155
	$ 120	$ 58	$ 19	$ 9	$ 6	$ 69	$ 281

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. As a short utility, 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, 2015, 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, 2015, PGE had no borrowings outstanding under its revolving credit facility and $6 million commercial paper 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, 2015, 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	2016	2017	2018	2019	There-after
First Mortgage Bonds	$ 2,318	$ 2,083	$ —	$ 58	$ 75	$ 300	$ 1,650
Pollution Control Revenue Bonds	137	121	—	—	—	—	121
Total	$ 2,455	$ 2,204	$ —	$ 58	$ 75	$ 300	$ 1,771

As of December 31, 2015, PGE had no long-term variable rate debt outstanding; accordingly, the Company's outstanding long-term debt is not subject to interest rate risk exposure. In January 2016, the Company issued $140 million of 2.51% Series FMBs due 2021 and redeemed the $58 million due in 2017 and the $75 million due in 2018 reflected in the table above.

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 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, 2015, PGE's credit risk exposure is $6 million for commodity activities with externally-rated investment grade counterparties and matures in 2017. The exposure is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Investment grade includes those counterparties 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, 2015 and 2014, 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, 2015. We also have audited the Company's internal control over financial reporting as of December 31, 2015, 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 audit 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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, 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, 2015, 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 11, 2016

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

	Years Ended December 31,		
	2015	**2014**	**2013**
Revenues, net	$ 1,898	$ 1,900	$ 1,810
Operating expenses:			
Purchased power and fuel	661	713	757
Generation, transmission and distribution	266	257	225
Cascade Crossing transmission project	—	—	52
Administrative and other	241	227	219
Depreciation and amortization	305	301	248
Taxes other than income taxes	116	109	103
Total operating expenses	1,589	1,607	1,604
Income from operations	309	293	206
Interest expense, net	114	96	101
Other income:			
Allowance for equity funds used during construction	21	37	13
Miscellaneous income, net	1	1	7
Other income, net	22	38	20
Income before income taxes	217	235	125
Income tax expense	45	61	21
Net income	172	174	104
Less: net loss attributable to noncontrolling interests	—	(1)	(1)
Net income attributable to Portland General Electric Company	$ 172	$ 175	$ 105
Weighted-average shares outstanding (in thousands):			
Basic	84,180	78,180	76,821
Diluted	84,341	80,494	77,388
Earnings per share:			
Basic	$ 2.05	$ 2.24	$ 1.36
Diluted	$ 2.04	$ 2.18	$ 1.35

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2015	**2014**	**2013**
Net income	$ 172	$ 174	$ 104
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of an immaterial amount in 2015, $2 in 2014, and ($1) in 2013	(1)	(2)	1
Comprehensive income	171	172	105
Less: comprehensive loss attributable to the noncontrolling interests	—	(1)	(1)
Comprehensive income attributable to Portland General Electric Company	$ 171	$ 173	$ 106

See accompanying notes to consolidated financial statements.

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

	As of December 31,	
	2015	**2014**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4	$ 127
Accounts receivable, net	158	149
Unbilled revenues	95	93
Inventories, at average cost:		
Materials and supplies	44	42
Fuel	39	40
Regulatory assets—current	129	133
Other current assets	88	115
Total current assets	557	699
Electric utility plant:		
Generation	3,898	3,742
Transmission	451	440
Distribution	3,192	3,075
General	463	426
Intangible	556	478
Construction work-in-progress	545	417
Total electric utility plant	9,105	8,578
Accumulated depreciation and amortization	(3,093)	(2,899)
Electric utility plant, net	6,012	5,679
Regulatory assets—noncurrent	524	494
Nuclear decommissioning trust	40	90
Non-qualified benefit plan trust	33	32
Other noncurrent assets	55	48
Total assets	$ 7,221	$ 7,042

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,	
	2015	**2014**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 98	$ 156
Liabilities from price risk management activities—current	130	106
Short-term debt	6	—
Current portion of long-term debt	133	375
Accrued expenses and other current liabilities	259	236
Total current liabilities	626	873
Long-term debt, net of current portion	2,071	2,126
Regulatory liabilities—noncurrent	928	906
Deferred income taxes	632	625
Unfunded status of pension and postretirement plans	259	237
Liabilities from price risk management activities—noncurrent	161	122
Asset retirement obligations	151	116
Non-qualified benefit plan liabilities	106	105
Other noncurrent liabilities	29	21
Total liabilities	4,963	5,131
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; 88,792,751 and 78,228,339 shares issued and outstanding as of December 31, 2015 and 2014, respectively	1,196	918
Accumulated other comprehensive loss	(8)	(7)
Retained earnings	1,070	1,000
Total equity	2,258	1,911
Total liabilities and equity	$ 7,221	$ 7,042

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				Noncontrolling Interests' Equity
	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	
	Shares	Amount			
Balance as of December 31, 2012	75,556,272	$ 841	$ (6)	$ 893	$ 2
Issuances of common stock, net of issuance costs of $3	2,365,000	67	—	—	—
Shares issued pursuant to equity-based plans	164,287	1	—	—	—
Stock-based compensation	—	2	—	—	—
Dividends declared ($1.095 per share)	—	—	—	(85)	—
Net income (loss)	—	—	—	105	(1)
Other comprehensive income	—	—	1	—	—
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 income	—	—	(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 (loss)	—	—	—	172	—
Other comprehensive loss	—	—	(1)	—	—
Balance as of December 31, 2015	88,792,751	$ 1,196	$ (8)	$ 1,070	$ —

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2015	**2014**	**2013**
Cash flows from operating activities:			
Net income	$ 172	$ 174	$ 104
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	305	301	248
Increase (decrease) in net liabilities from price risk management activities	60	45	(18)
Regulatory deferrals—price risk management activities	(60)	(45)	18
Cascade Crossing transmission project	—	—	52
Deferred income taxes	40	39	11
Allowance for equity funds used during construction	(21)	(37)	(13)
Pension and other postretirement benefits	34	33	37
Regulatory deferral of settled derivative instruments	2	10	7
Unrealized losses on non-qualified benefit plan trust assets	6	7	3
Decoupling mechanism deferrals, net of amortization	14	6	(6)
Power cost deferrals, net of amortization	—	—	(6)
Other non-cash income and expenses, net	17	12	18
Changes in working capital, net of effects from purchase of 10% interest in Boardman in 2014:			
(Increase) decrease in receivables and unbilled revenues	(11)	8	—
(Increase) decrease in margin deposits	(22)	(2)	37
Increase (decrease) in payables and accrued liabilities	6	(13)	14
Other working capital items, net	(4)	(12)	17
Cash received to be returned to customers pursuant to the Residential Exchange Program, net of amortization	(1)	13	1
Proceeds received from Trojan spent fuel legal settlement	—	6	44
Contribution to non-qualified employee benefit trust	(9)	(8)	(6)
Contribution to voluntary employees' benefit association trust	(4)	(3)	(3)
Other, net	(7)	(16)	(15)
Net cash provided by operating activities	517	518	544
Cash flows from investing activities:			
Capital expenditures	(598)	(1,007)	(656)
Purchases of nuclear decommissioning trust securities	(19)	(19)	(26)
Sales of nuclear decommissioning trust securities	22	17	25
Distribution from (contribution to) nuclear decommissioning trust	50	(6)	(44)
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	—
Proceeds received from insurance recoveries	—	3	6
Proceeds from sale of properties	—	5	—
Other, net	—	5	3
Net cash used in investing activities	(522)	(994)	(692)

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,		
	2015	**2014**	**2013**
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 145	$ 585	$ 380
Payments on long-term debt	(442)	—	(100)
Proceeds from issuances of common stock, net of issuance costs	271	—	67
Borrowings on short-term debt	—	—	35
Payments on short-term debt	—	—	(35)
Issuance (maturities) of commercial paper, net	6	—	(17)
Dividends paid	(97)	(87)	(84)
Debt issuance costs	(1)	(2)	(3)
Net cash (used in) provided by financing activities	(118)	496	243
(Decrease) increase in cash and cash equivalents	(123)	20	95
Cash and cash equivalents, beginning of year	127	107	12
Cash and cash equivalents, end of year	$ 4	$ 127	$ 107
Supplemental disclosures of cash flow information:			
Cash paid for:			
Interest, net of amounts capitalized	$ 108	$ 86	$ 90
Income taxes	3	22	10
Non-cash investing and financing activities:			
Accrued capital additions	32	70	84
Accrued dividends payable	28	23	22
Accrued sales tax refund related to Tucannon River Wind Farm	—	23	—
Preliminary engineering transferred to Construction work in progress from Other noncurrent assets	—	—	9

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 sells electricity and natural gas in the wholesale market to utilities, brokers, and power marketers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE's corporate headquarters is located in Portland, Oregon and its service area is located entirely within Oregon. PGE's service area includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. As of December 31, 2015, PGE served 852,164 retail customers with a service area population of approximately 1.8 million, comprising approximately 46% of the state's population.

As of December 31, 2015, PGE had 2,646 employees, with 764 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 713 and 51 employees and expire at the end of February 2016, (the Company is currently in negotiation to renew or extend) 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 and its wholly-owned subsidiaries and those variable interest entities (VIEs) where 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. Intercompany balances and transactions have been eliminated.

For entities that are determined to meet the definition of a VIE and where 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. For further information, see Note 16, Variable Interest Entities.

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.

Customer Billing Matter

In May 2013, PGE discovered that it had over-billed an industrial customer during a period of several years as a result of a meter configuration error. An analysis of the data determined that the Company's revenues were overstated by approximately $3 million in 2012 and in 2011, $2 million in 2010, and $1 million in 2009. PGE believes the customer billing error is not material to any annual reporting period. The Company corrected this matter in the second quarter of 2013 as an out of period adjustment, and recorded, as a reduction to Revenues, net, a refund to the customer in the amount of $9 million.

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 none as of December 31, 2015 and $120 million as of December 31, 2014.

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 2015, 2014 and 2013.

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 with Other current assets in the consolidated balance sheets and were $33 million and $11 million as of December 31, 2015 and 2014, respectively. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheet and were $63 million and $30 million as of December 31, 2015 and 2014, 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 2015, 7.4% in 2014, and 7.5% in 2013. AFDC from borrowed funds was $13 million in 2015, $22 million in 2014, and $7 million in 2013 and is reflected as a reduction to Interest expense. AFDC from equity funds was $21 million in 2015, $37 million in 2014, and $13 million in 2013 and is included in Other income, net.

The Company is constructing the Carty Generating Station (Carty), a 440 MW baseload natural gas-fired generating plant in Eastern Oregon, located adjacent to the Boardman coal plant. As of December 31, 2015, PGE had $424 million, including $41 million of AFDC, included in CWIP for the project. 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 will be included in customer prices when the plant is placed in service, provided that occurs by July 31, 2016.

In 2013, the Company entered into an agreement (Construction Agreement) for engineering, procurement and construction of Carty with Abeinsa Abener Teyma General Partnership (Contractor or Abeinsa). On December 18, 2015

, the Company declared Abeinsa in default under multiple provisions of the Construction Agreement and terminated the Construction Agreement. Liberty Mutual Surety and Zurich North America (Sureties) have provided a performance bond of $145.6 million under the Construction Agreement. The Company had required Abeinsa to enter into the performance bond to guarantee satisfactory completion of the project in the event the Contractor failed to fulfill its obligations under 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. The Company is currently in discussions with the Sureties regarding their obligations under the performance bond. The Company believes that the Sureties will have an obligation under the performance bond to contribute funds towards the completion of Carty. However, the Sureties have not yet made a determination with respect to their obligations.

On January 28, 2016, PGE received notice from the International Court of Arbitration that Abengoa S.A., the parent company of the Contractor, had submitted a Request for Arbitration in which it 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 liability of Abengoa S.A. under the terms of a guaranty in favor of PGE 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 intends to contest the arbitration claim.

As a result of the termination of the Construction Agreement, the transition to a new construction team, and related matters, additional costs are expected to be incurred to complete construction of Carty, including, among other things, costs related to determining the remaining scope of construction, re-performing work performed by the Contractor that did not meet specifications, completing an inventory of materials either on-site, ordered or in transit, preparing work plans for contractors, identifying new contractors, negotiating contracts, procuring additional materials, completing unfinished construction, and removing liens on the property. PGE currently expects the total cost of Carty could range from $620 million to $655 million, including AFDC, and is targeted to be placed in service in July 2016. However, due to uncertainties relating to the transition to the new construction team and any other unknown factors related to the completion of construction, estimated completion date and costs could change. The total project cost would be reduced by any amounts received pursuant to the Sureties’ obligations under the performance bond. However, the amount of any such proceeds remains uncertain and cannot be reasonably estimated at this time.

In the event the total project costs incurred by PGE, net of any amounts received under the performance bond, exceed the OPUC’s approved amount of $514 million, including AFDC, the Company would seek approval to recover the excess amounts in customer prices in a subsequent GRC proceeding. However, there is no assurance that such recovery would be granted by the OPUC. If the Carty placed in service date were to be delayed beyond July 31, 2016, PGE would pursue one or more alternative avenues to obtain OPUC approval for the inclusion of Carty costs in customer prices in future GRC filings. Under such circumstance, the Company might not be able to recover some, or all, of the net revenue requirements for Carty from the date Carty is placed into service until the time approved rates go in effect.

During the year ended December 31, 2013, PGE charged $52 million of costs previously included in CWIP related to the Cascade Crossing Transmission Project (Cascade Crossing), which was originally proposed as a 215-mile, 500 kV transmission project between Boardman, Oregon and Salem, Oregon. Based on an updated forecast of demand and future transmission capacity in the region, PGE determined in the second quarter of 2013 that the original projections of transmission capacity limitations contemplated in the Company’s 2009 Integrated Resource Plan, as acknowledged by the OPUC, were not likely to fully materialize. The Company also suspended permitting and development of Cascade Crossing and charged the related capitalized costs to expense. PGE determined that it would not seek recovery of those costs.

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 3.6% in 2015, 3.6% in 2014, and 3.7% in 2013. Estimated asset retirement removal costs included in depreciation expense were $32 million in 2015, $57 million in 2014, and $55 million in 2013.

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.

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 $227 million and $191 million as of December 31, 2015 and 2014, respectively, with amortization expense of $38 million in 2015, and $25 million in 2014 and $22 million in 2013. Future estimated amortization expense as of December 31, 2015 is as follows: $43 million in 2016; $40 million in 2017; $39 million in 2018; $33 million in 2019; and $23 million in 2020.

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 9.68% for 2015, 9.75% for 2014, and 10% for 2013.

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 $45 million as of December 31, 2015 and $39 million as of December 31, 2014. 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. 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. Legal costs incurred in connection with loss contingencies are expensed as incurred.

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), and 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 2015, $42 million in 2014, and $41 million in 2013.

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 which has not been billed as of the last day of the month. Unbilled revenue 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 retail customer prices.

As a rate-regulated utility, there are situations in which PGE 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.

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 is established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

As 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. These amounts were recognized as net regulatory assets of $86 million as of December 31, 2015 and 2014 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 or as a cumulative-effect adjustment as of the date of adoption, which was originally January 1, 2017 for the Company. In August 2015, the Financial Accounting Standards Board (FASB) issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date* (ASU 2014-14) that defers the effective date by one year, although it permits early adoption as of the original effective date. 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 2014-09.

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 provisions of ASU 2015-03 are effective for fiscal years beginning after December 15, 2015, or January 1, 2016 for PGE, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. The provisions should be applied on a retrospective basis. Upon transition, an entity is required to comply with the applicable disclosures for a change in an accounting principle, which includes: i) the nature of and reason for the change in accounting principle; ii) the transition method; iii) a description of the prior-period information that has been retrospectively adjusted; and iv) the effect of the change on the financial statement line items. 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. PGE will adopt the amendments contained in ASU 2015-03 and 2015-15 on January 1, 2016, which is not expected to have a material impact on PGE’s consolidated financial position, consolidated results of operation, or consolidated cash flows.

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 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 practical expedient. Instead, such disclosures are restricted only to investments that the entity has decided to measure using the practical expedient. This standard is effective for interim and annual periods beginning after December 15, 2015. PGE will adopt the amendments contained in ASU 2015-07 on January 1, 2016, which is not expected to have an impact on the Company’s consolidated financial position, consolidated results of operations, or consolidated cash flows.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 330), Simplifying the Measurement of Inventory* (ASU 2015-11), which changes the measurement principle for inventory from the lower of cost or market to lower of cost and net realizable value. Net realizable value is defined as the “estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation.” ASU 2015-11 eliminates the guidance that entities consider replacement cost or net realizable value less an approximately normal profit margin in the subsequent measurement of inventory when cost is determined on a first-in, first-out or average cost basis. The provisions of ASU 2015-11 are effective for public entities with fiscal years beginning after December 15, 2016, or January 1, 2017 for PGE, and interim periods within those fiscal years. 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 2015-11.

In January 2016, the FASB issued ASU 2016-01, *Financial Instrument-Overall (Subtopic 825-10), Recognition and Measurement of Financial Assets and Financial Liabilities* (ASU 2016-01), which enhances the reporting model for financial instruments and related disclosures. The main provisions of the ASU will include: i) requirements to measure equity investments (except those accounted for under the equity method of accounting) at fair value with changes in fair value recognized in net income; ii) simplification of the impairment assessment of equity investments without readily determinable fair values; iii) eliminate the requirement to disclose the method(s) and significant assumptions used to estimate the fair value that is required to be disclosed for financial instruments measured at amortized cost on the balance sheet; iv) requirement to use the exit price notion when measuring the fair value of financial instruments for disclosure purposes; v) require an entity to present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk when the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments; and vi) require separate presentation of financial assets and financial liabilities by measurement category and form of financial asset on the balance sheet or footnotes. The provisions of ASU 2016-01 are effective for public entities with fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is permitted, in certain circumstances. 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 2015-11.

Newly Adopted Accounting Standard

In November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740), Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies financial reporting by removing the requirement to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified balance sheet, and instead requires these amounts to be classified solely as noncurrent. This standard is effective for financial statements issued for annual periods beginning after December 15, 2016. The amendment can be applied prospectively or retrospectively and early adoption is permitted. PGE has opted to early adopt the change in accounting principle on a prospective basis and is reflected as such within the balance sheet for the period ended December 31, 2015. Prior periods were not retrospectively adjusted.

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, 2015 and 2014. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2015	2014	2013
Balance as of beginning of year	$ 6	$ 6	$ 5
Increase in provision	6	6	6
Amounts written off, less recoveries	(6)	(6)	(5)
Balance as of end of year	$ 6	$ 6	$ 6

Trust Accounts

PGE maintains two trust accounts as follows:

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	
	2015	2014	2015	2014
Cash equivalents	$ 18	$ 65	$ 1	$ —
Marketable securities, at fair value:				
Equity securities	—	—	5	6
Debt securities	22	25	1	—
Insurance contracts, at cash surrender value	—	—	26	26
	$ 40	$ 90	$ 33	$ 32

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,	
	2015	2014
Other current assets:		
Prepaid expenses	$ 43	$ 39
Current deferred income tax asset	—	33
Accrued sales tax refund related to Tucannon River Wind Farm	—	23
Margin deposits	33	11
Assets from price risk management activities	10	6
Other	2	3
	$ 88	$ 115
Accrued expenses and other current liabilities:		
Regulatory liabilities—current	$ 55	$ 60
Accrued employee compensation and benefits	51	51
Accrued interest payable	25	26
Accrued dividends payable	28	23
Accrued taxes payable	25	22
Other	75	54
	$ 259	$ 236

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, 2015 and 2014, 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 reporting date.

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

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, 2015 and 2014, except those transfers from Level 3 to Level 2 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, 2015			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust: [1]				
Money market funds	$ —	$ 18	$ —	$ 18
Debt securities:				
Domestic government	6	8	—	14
Corporate credit	—	8	—	8
Non-qualified benefit plan trust: [2]				
Money market funds	—	1	—	1
Equity securities:				
Domestic	3	2	—	5
International	—	—	—	—
Debt securities - domestic government	1	—	—	1
Assets from price risk management activities: [1] [3]				
Electricity	—	7	—	7
Natural gas	—	3	—	3
	$ 10	$ 47	$ —	$ 57
Liabilities - Liabilities from price risk management activities: [1] [3]				
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) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

	As of December 31, 2014			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust: (1)				
Money market funds	$ —	$ 65	$ —	$ 65
Debt securities:				
Domestic government	7	7	—	14
Corporate credit	—	11	—	11
Non-qualified benefit plan trust: (2)				
Equity securities:				
Domestic	4	1	—	5
International	1	—	—	1
Assets from price risk management activities: (1) (3)				
Electricity	—	4	1	5
Natural gas	—	2	—	2
	$ 12	$ 90	$ 1	$ 103
Liabilities - Liabilities from price risk management activities: (1) (3)				
Electricity	$ —	$ 32	$ 80	$ 112
Natural gas	—	95	21	116
	$ —	$ 127	$ 101	$ 228

(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) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(3) 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:

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. Money market funds are classified as Level 2 in the fair value hierarchy as the securities are traded in active markets of similar securities but are not directly valued using quoted market prices.

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 reporting 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 primarily 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 reporting date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE). Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 in the fair value hierarchy as pricing inputs are directly or indirectly observable in the marketplace.

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, 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					
As of December 31, 2014:							
Electricity physical forward	$ —	$ 77	Discounted cash flow	Electricity forward price (per MWh)	$ 11.97	$ 122.72	$ 37.43
Natural gas financial swaps	—	21	Discounted cash flow	Natural gas forward price (per Dth)	2.88	4.86	3.41
Electricity financial futures	1	3	Discounted cash flow	Electricity forward price (per MWh)	11.97	39.26	27.88
	$ 1	$ 101					

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, the Company 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 monthly 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,	
	2015	2014
Net liabilities from price risk management activities as of beginning of year	$ 100	$ 139
Net realized and unrealized losses *	80	15
Settlements	—	(4)
Net transfers out of Level 3 to Level 2	(61)	(50)
Net liabilities from price risk management activities as of end of year	$ 119	$ 100
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 80	$ 12

* Includes nominal net realized losses in 2015 and $3 million in 2014.

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 years ended December 31, 2015 and 2014, there were no significant transfers into Level 3 from Level 2. 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, 2015, the carrying amount of PGE's long-term debt was $2,204 million and its estimated aggregate fair value was $2,455 million, classified as Level 2 in the fair value hierarchy. As of December 31, 2014, the carrying amount of PGE's long-term debt was $2,501 million and its estimated aggregate fair value was $2,901 million, consisting of $2,596 million, classified as Level 2 and $305 million classified as Level 3, respectively, 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 generating resources 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 fuel and power purchases and sales resulting from economic dispatch decisions for its own generation. As a result of this ongoing
business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, where adverse changes in prices and/or rates may affect the Company's financial position, performance, or cash flow.

PGE utilizes derivative instruments in its wholesale electric utility activities to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in net power costs for its retail customers. These derivative instruments may include forward, futures, swap, and option contracts for electricity, natural gas, oil and foreign currency, which are recorded at fair value on the consolidated balance sheet, with changes in fair value recorded in the statement of income. In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE 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. PGE 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,	
	2015	2014
Current assets:		
Commodity contracts:		
Electricity	$ 7	$ 4
Natural gas	3	2
Total current derivative assets	10 (1)	6 (1)
Noncurrent assets:		

Commodity contracts:		
Electricity	—	1
Total noncurrent derivative assets	— (2)	1 (2)
Total derivative assets not designated as hedging instruments	$ 10	$ 7
Total derivative assets	$ 10	$ 7
Current liabilities:		
Commodity contracts:		
Electricity	$ 36	$ 54
Natural gas	94	52
Total current derivative liabilities	130	106
Noncurrent liabilities:		
Commodity contracts:		
Electricity	97	58
Natural gas	64	64
Total noncurrent derivative liabilities	161	122
Total derivative liabilities not designated as hedging instruments	$ 291	$ 228
Total derivative liabilities	$ 291	$ 228

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

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,					
	2015			2014		
Commodity contracts:						
Electricity		12	MWh		16	MWh
Natural gas		124	Dth		127	Dth
Foreign currency exchange	$	7	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, these agreements provide for the net settlement of all related contractual obligations with a 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, 2015 and 2014, gross amounts included as Price risk management liabilities subject to master netting agreements were $111 million and $72 million, respectively, for which PGE posted collateral of $14 million and $11 million, which consisted entirely of letters of credit. As of December 31, 2015, of the gross amounts included, $104 million was for electricity and $7 million was for natural gas compared to $55 million for electricity and $17 million for natural gas recognized as of December 31, 2014.

Net realized and unrealized losses 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,					
	2015		2014		2013	
Commodity contracts:						
Electricity	$	72	$	13	$	78
Natural Gas		103		72		28
Foreign currency exchange		1		—		1

Net unrealized losses and certain net realized losses presented in the table above are offset within the consolidated statement of income by the effects of regulatory accounting. Of the net loss recognized in Net income for the years ended December 31, 2015, 2014, and 2013, $160 million, $83 million, and $120 million, respectively, have been offset.

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, 2015 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2016		2017		2018		2019		2020		Thereafter		Total	
Commodity contracts:														
Electricity	$	29	$	8	$	7	$	7	$	6	$	69	$	126
Natural gas		91		50		12		2		—		—		155
Net unrealized loss	$	120	$	58	$	19	$	9	$	6	$	69	$	281

PGE’s secured and unsecured debt is currently rated at investment grade by Moody’s Investors Service (Moody’s) and Standard & Poor’s Ratings Services (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, 2015 was $278 million, for which the Company had posted $80 million in collateral, consisting of $61 million in letters of credit and $19 million in cash. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2015, the cash requirement to either post as collateral or settle the instruments immediately would have been $255 million. As of December 31, 2015, PGE had posted an additional $14 million in cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivatives 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,	
	2015	**2014**
Assets from price risk management activities:		
Counterparty A	59%	63%
Counterparty B	10	14
	69%	77%
Liabilities from price risk management activities:		
Counterparty C	36%	22%
Counterparty D	10	7
Counterparty E	10	9
Counterparty F	5	12
	61%	50%

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,			
		2015		2014	
		Current	Noncurrent	Current	Noncurrent
Regulatory assets:					
Price risk management [2]	4 years	$ 120	$ 161	$ 100	$ 121
Pension and other postretirement plans [2]	[3]	—	239	—	247
Deferred income taxes [2]	[4]	—	86	—	86
Debt issuance costs [2]	8 years	—	16	—	15
Deferred capital projects	1 year	—	—	19	—
Other [5]	Various	9	22	14	25
Total regulatory assets		$ 129	$ 524	$ 133	$ 494
Regulatory liabilities:					
Asset retirement removal costs [6]	[4]	$ —	$ 837	$ —	$ 804
Trojan decommissioning activities	3 years	17	15	23	34
Asset retirement obligations [6]	[4]	—	45	—	39
Other	Various	38	31	37	29
Total regulatory liabilities		$ 55 [7]	$ 928	$ 60 [7]	$ 906

(1) As of December 31, 2015.
(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 $29 million and $33 million as of December 31, 2015 and 2014, 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, 2015, PGE had regulatory assets of $30 million earning a return on investment at the following rates: i) $25 million earning a return by inclusion in rate base; ii) $4 million at the approved rate for deferred accounts under amortization, ranging from 1.47% to 1.93%, depending on the year of approval; and iii) $1 million at PGE's 2015 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.

Deferred capital projects represents costs related to four capital projects that were deferred for future accounting treatment pursuant to the Company's 2011 GRC. The recovery of these project costs in customer prices began January 1, 2014 and was fully amortized as of December 31, 2015.

Asset retirement removal costs represent 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 represent 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,	
	2015	**2014**
Trojan decommissioning activities	$ 43	$ 41
Utility plant	97	64
Non-utility property	11	11
Asset retirement obligations	$ 151	$ 116

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 approximately $112 million in damages incurred through 2009.

A trial before the U.S. Court of Federal Claims concluded in 2012, with the U.S. Court of Federal Claims issuing a judgment awarding certain damages to the Plaintiffs. In 2013, the Plaintiffs received $70 million for the settlement of this matter. The settlement agreement also provides for a process to submit claims for allowable costs for the period 2010 through 2016, and pursuant to this process the Plaintiffs received $9 million in 2014 for costs related to the 2010 through 2013 time period. The Company will seek recovery of costs under the current settlement agreement, as well as any subsequent extensions of the agreement to cover future periods.

PGE has received proceeds of $50 million related to its share in this legal matter, with $44 million received in 2013 and $6 million received in 2014. Such funds were deposited into the Nuclear decommissioning trust and 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 the $50 million of proceeds received related to this legal matter to customers over a three-year period beginning January 1, 2015. In early 2015, a distribution was made from the Nuclear decommissioning trust in the amount of $50 million to be refunded to customers over the three year period that began 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 2015, the Company recorded an overall increase in AROs of $33 million, with the change comprised of an increase to revisions in estimated cash flows and incurred liabilities of $30 million, accretion of $4 million, and a reduction of $1 million due to settled liabilities.

In 2015 and 2014, PGE increased its ARO related to Boardman by $9 million and $7 million, respectively, due primarily to changes in timing of estimated settlements and due to the acquisition of additional interests in Boardman, with corresponding increases in the cost basis of the plant, included in Electric utility plant, net on the consolidated balance sheet. For additional information regarding the Company’s acquisition of additional interests in Boardman, see Note 17, 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.

Colstrip utilizes wet scrubbers and a number of settlement ponds that will require upgrading or closure to meet the new regulatory requirements. The operator of Colstrip has provided an initial cost estimate related to the impacts of the final EPA rule. As a result, during 2015, the Company recorded an increase to the existing Colstrip AROs in the amount of $17 million, with a corresponding increase in the cost basis of the plant, included in Electric utility plant, net on the consolidated balance sheet. PGE plans to seek recovery in customer prices of the incremental costs associated with the final EPA rule.

In 2015, PGE also recorded AROs totaling $4 million 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,		
	2015	2014	2013
Balance as of beginning of year	$ 116	$ 100	$ 94
Liabilities incurred	2	15	4
Liabilities settled	(4)	(3)	(4)
Accretion expense	7	6	6
Revisions in estimated cash flows	30	(2)	—
Balance as of end of year	$ 151	$ 116	$ 100

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, 2015, PGE had a $500 million 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 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 provisions 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% of total capitalization. As of December 31, 2015, PGE was in compliance with this covenant with a 49.5% 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 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 credit facility, as of December 31, 2015, PGE had $6 million of commercial paper outstanding and no borrowings or letters of credit issued. As of December 31, 2015, the aggregate unused available credit capacity under the revolving credit facility was $494 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, $108 million of letters of credit was outstanding, as of December 31, 2015.

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,		
	2015	2014	2013
Average daily amount of short-term debt outstanding	$ —	$ —	$ 9
Weighted daily average interest rate *	0.6%	—%	0.4%
Maximum amount outstanding during the year	$ 11	$ —	$ 54

* 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,	
	2015	2014
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.29% in 2015 and 5.42% in 2014, due at various dates through 2048	$ 2,083	$ 2,075
Unsecured term bank loans, rates range from 0.86% to 0.93%, due October 2015	—	305
Pollution Control Revenue Bonds, 5% rate, due 2033	142	142
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Total long-term debt	2,204	2,501
Less: current portion of long-term debt	(133)	(375)
Long-term debt, net of current portion	$ 2,071	$ 2,126

First Mortgage Bonds and Unsecured term bank loans—During 2015, PGE issued a total of $145 million of FMBs and repaid long-term debt, inclusive of the Unsecured term bank loans, in an aggregate amount of $442 million, as follows:

- In January, issued $75 million of 3.55% Series FMBs due 2030 and repaid $70 million of 3.46% Series FMBs;
- In February, repaid $50 million of long-term bank loans;
- In May, issued $70 million of 3.5% Series FMBs due 2035 and repaid $67 million of 6.80% Series FMBs, due January 2016;

- In June, repaid $200 million of long-term bank loans; and
- In July, repaid the remaining outstanding balance of long-term debt bank loans in the amount of $55 million.

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 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.

During 2014, PGE obtained four unsecured term bank loans pursuant to a credit agreement in an aggregate principal amount of $305 million. The credit agreement was set to expire October 30, 2015, at which time any amounts outstanding under the term loans were to become due and payable. The Company fully repaid these term loans early with the final payment made in July 2015.

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, 2015. 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, 2015, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2016	$	—
2017		58
2018		75
2019		300
2020		—
Thereafter		1,771
	$	2,204

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan. The plan 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 which are reviewed annually and are updated as appropriate, with the measurement date of December 31.

PGE made no contributions to the pension plan in 2015, 2014, and 2013. No contributions to the pension plan are expected in 2016.

In 2014, the Company offered certain eligible participants of 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 paying 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 which are reviewed annually with PGE’s consulting actuaries and trust investment consultants 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, the participants’ accounts are credited with 58% of the value of the employee’s accumulated sick time as of April 30, 2004, 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. These trust assets 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 which 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):

	2015			2014		
	NQBP	**Other NQBP**	**Total**	**NQBP**	**Other NQBP**	**Total**
Non-qualified benefit plan trust	$ 15	$ 18	$ 33	$ 15	$ 17	$ 32
Non-qualified benefit plan liabilities *	25	81	106	25	80	105

* For the NQBP, excludes the current portion of $2 million in 2015 and 2014, which is 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. In addition, the Board also 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,			
	2015		2014	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	67%	67%	66%	67%
Debt securities	33	33	34	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	60%	64%	66%	67%
Debt securities	40	36	34	33
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	15%	14%	19%	13%
Debt securities	7	8	1	7
Insurance contracts	78	78	80	80
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.

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	Total
As of December 31, 2015:				
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 5	$ —	$ 5
Equity securities:				
Domestic	$ 44	$ 132	$ —	$ 176
International	—	170	—	170
Debt securities:				
Domestic government and corporate credit	—	177	—	177
Private equity funds	—	—	22	22
	$ 44	$ 484	$ 22	$ 550
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 7	$ —	$ 7
Equity securities:				
Domestic	—	10	—	10
International	8	—	—	8
Debt securities—Domestic government	—	5	—	5
	$ 8	$ 22	$ —	$ 30
As of December 31, 2014:				
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 6	$ —	$ 6
Equity securities:				
Domestic	$ 42	$ 146	$ —	$ 188
International	—	171	—	171
Debt securities:				
Domestic government and corporate credit	—	197	—	197
Private equity funds	—	—	29	29
	$ 42	$ 520	$ 29	$ 591
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 6	$ —	$ 6
Equity securities:				
Domestic	10	1	—	11
International	10	—	—	10
Debt securities—Domestic government	5	—	—	5
	$ 25	$ 7	$ —	$ 32

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 methods are used in valuation of each asset class of 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, certificates of deposit, and commercial paper. Money market funds held in the trusts are classified as Level 2 instruments as they are traded in an active market of similar securities but are not directly valued using quoted prices.

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 commingled trusts or separately managed accounts are classified as Level 2 securities due to pricing inputs that are not directly or indirectly observable in the marketplace.

Debt securities—PGE invests in highly-liquid United States treasury and corporate credit mutual fund securities to support the investment objectives of the trusts. These securities are classified as Level 1 instruments due to the highly observable nature of pricing in an active market.

Fair values for Level 2 debt securities, including municipal debt and corporate credit securities, mortgage-backed securities and asset-backed securities are determined by evaluating pricing data, such as broker quotes, for similar securities 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 if applicable.

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, venture capital, buyout, and special situations. Private equity investments are classified as Level 3 securities due to fund valuation methodologies that utilize discounted cash flow, market comparable and limited secondary market pricing to develop estimates of fund valuation. PGE valuation of individual fund performance compares stated fund performance against published benchmarks.

Changes in the fair value of assets held by the pension plan classified as Level 3 in the fair value hierarchy, which consists of Private equity funds, were as follows (in millions):

	Years Ended December 31,	
	2015	2014
Level 3 balance as of beginning of year	$ 29	$ 31
Unrealized (losses) gains, net	(2)	2
Realized gains, net	4	3
Sales, net	(9)	(7)
Level 3 balance as of end of year	$ 22	$ 29

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, 2015 and 2014. 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	
	2015	2014	2015	2014	2015	2014
Benefit obligation:						
As of January 1	$ 777	$ 705	$ 83	$ 77	$ 27	$ 24
Service cost	18	15	2	2	—	—
Interest cost	31	34	3	4	1	1
Participants' contributions	—	—	2	1	—	—
Actuarial (gain) loss	(31)	72	(4)	4	1	5
Contractual termination benefits	—	—	1	1	—	—
Benefit payments	(35)	(48)	(6)	(6)	(2)	(3)
Administrative expenses	(2)	(1)	—	—	—	—
As of December 31	$ 758	$ 777	$ 81	$ 83	$ 27	$ 27
Fair value of plan assets:						
As of January 1	$ 591	$ 596	$ 32	$ 32	$ 15	$ 16
Actual return on plan assets	(4)	44	(2)	1	—	1
Company contributions	—	—	4	4	2	1
Participants' contributions	—	—	2	1	—	—
Benefit payments	(35)	(48)	(6)	(6)	(2)	(3)
Administrative expenses	(2)	(1)	—	—	—	—
As of December 31	$ 550	$ 591	$ 30	$ 32	$ 15	$ 15
Unfunded position as of December 31	$ (208)	$ (186)	$ (51)	$ (51)	$ (12)	$ (12)
Accumulated benefit plan obligation as of December 31	$ 681	$ 691	N/A	N/A	$ 27	$ 27
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 15	$ 15
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(208)	(186)	(51)	(51)	(25)	(25)
Net liability	$ (208)	$ (186)	$ (51)	$ (51)	$ (12)	$ (12)
Amounts included in comprehensive income:						
Net actuarial loss	$ 13	$ 67	$ —	$ 5	$ 1	$ 5
Amortization of net actuarial loss	(20)	(17)	(1)	(1)	(1)	(1)
Amortization of prior service cost	—	—	(1)	(1)	—	—
	$ (7)	$ 50	$ (2)	$ 3	$ —	$ 4
Amounts included in AOCL*:						
Net actuarial loss	$ 228	$ 236	$ 9	$ 10	$ 13	$ 13
Prior service cost	—	—	1	1	—	—
	$ 228	$ 236	$ 10	$ 11	$ 13	$ 13

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2015	2014	2015	2014	2015	2014
Assumptions used:						
Discount rate for benefit obligation	4.36%	4.02%	3.90% - 4.45%	3.07% - 4.10%	4.36%	4.02%
Discount rate for benefit cost	4.02%	4.84%	3.07% - 4.10%	3.46% - 4.96%	4.02%	4.84%
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%	6.29%	6.37%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	7.50%	7.50%	6.37%	6.46%	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		
	2015	2014	2013	2015	2014	2013	2015	2014	2013
Service cost	$ 18	$ 15	$ 17	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	31	34	30	3	4	3	1	1	1
Expected return on plan assets	(40)	(39)	(40)	(2)	(2)	(1)	—	—	—
Amortization of prior service cost	—	—	—	1	1	1	—	—	—
Amortization of net actuarial loss	20	17	24	1	1	1	1	1	1
Net periodic benefit cost	$ 29	$ 27	$ 31	$ 5	$ 6	$ 6	$ 2	$ 2	$ 2

PGE estimates that $16 million will be amortized from AOCL into net periodic benefit cost in 2016, consisting of a net actuarial loss of $14 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					
	2016	2017	2018	2019	2020	2021 - 2025
Defined benefit pension plan	$ 37	$ 38	$ 40	$ 41	$ 42	$ 226
Other postretirement benefits	5	5	5	5	5	26
Non-qualified benefit plans	2	2	2	3	2	10
Total	$ 44	$ 45	$ 47	$ 49	$ 49	$ 262

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 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;
- 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; and
- For 2013, 7.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2014, 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 $17 million in 2015, and $16 million in both 2014 and 2013.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,		
	2015	**2014**	**2013**
Current:			
Federal	$ 4	$ 20	$ 10
State and local	1	2	—
	5	22	10
Deferred:			
Federal	26	26	4
State and local	14	13	7
	40	39	11
Income tax expense	$ 45	$ 61	$ 21

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,		
	2015	2014	2013
Federal statutory tax rate	35.0 %	35.0 %	35.0 %
Federal tax credits	(19.0)	(11.4)	(21.8)
State and local taxes, net of federal tax benefit	4.2	3.9	3.4
Flow through depreciation and cost basis differences	—	(2.3)	2.8
Other	0.5	0.8	(2.6)
Effective tax rate	20.7 %	26.0 %	16.8 %

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

	As of December 31,	
	2015	2014
Deferred income tax assets:		
Employee benefits	$ 170	$ 161
Price risk management	112	88
Regulatory liabilities	42	48
Tax credits	46	13
Other	—	1
Total deferred income tax assets	370	311
Deferred income tax liabilities:		
Depreciation and amortization	781	693
Regulatory assets	220	210
Other	1	—
Total deferred income tax liabilities	1,002	903
Deferred income tax liability, net	$ (632)	$ (592)
Classification of net deferred income taxes:		
Current deferred income tax asset (1)(2)	$ —	$ 33
Noncurrent deferred income tax liability	(632)	(625)
	$ (632)	$ (592)

(1) Included in Other current assets in the consolidated balance sheets.
(2) Current deferred income tax asset was not retrospectively restated for the adoption of ASU 2015-17, *Balance Sheet Classification of Deferred Taxes*. For additional information, see Note 2, Summary of Significant Accounting Policies.

As of December 31, 2015, PGE has federal and state tax credit carryforwards of $42 million and $4 million, respectively, which will expire at various dates from 2023 through 2035.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2015 and 2014 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2015 and 2014, PGE had no unrecognized tax benefits.

PGE and its subsidiaries file a consolidated federal income tax return. The Company also files state income tax returns in certain jurisdictions, including Oregon, California, Montana, and 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.

The Protecting Americans from Tax Hikes Act of 2015 (PATH) was signed into law on December 18, 2015. Among other items, the PATH extended provisions for bonus depreciation and production tax credits through 2019, inclusive of certain phase-down schedules. In the event PGE qualifies for future production tax credits related to the construction of new wind generation facilities or deems the application of bonus depreciation favorable, the Company will consider utilizing some of the PATH's extended provisions. As of December 31, 2015, no provision materially impacts the Company's current consolidated financial position.

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 connection with such public offering, the underwriters exercised their over-allotment option in full and PGE issued 1,665,000 shares of its common stock for net proceeds of $47 million. PGE received proceeds from the sale of common stock when the EFSA was physically settled (described below), and at that time PGE issued new shares of common stock and recorded the proceeds in equity. In the third quarter of 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. There are two six-month offering periods each year, 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, 2015, there were 397,265 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, 2015, there were 2,478,086 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, 2012	440,562	$ 22.54
Granted	183,071	29.25
Forfeited	(7,007)	27.15
Vested	(185,536)	20.20
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

A total of 4,687,500 shares of common stock were registered for future issuance under the Plan, of which 3,443,904 shares remain available for future issuance as of December 31, 2015.

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, 2015, 2014, and 2013.

Performance-based RSUs vest if performance goals are met at the end of a three-year performance period. For grants prior to March 5, 2013, such goals include return on equity relative to allowed return on equity, and regulated asset base growth. Grants on and after March 5, 2013 are based on three equally-weighted metrics: return on equity relative to allowed return on equity; regulated asset growth; and 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:

	2015	2014
Risk-free interest rate	1.0%	0.6%
Expected dividend yield	—%	—%
Expected term (in years)	3.0	3.0
Volatility	13.2% - 19.2%	12.4% - 23.0%

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 130.1%, 132.4%, and 111.7% of awarded performance-based RSUs for the respective 2015, 2014, and 2013 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $4 million for the year ended December 31, 2015, and $3 million for the years ended 2014 and 2013, respectively.

Stock-based compensation was $6 million for the year ended December 31, 2015, and 2014, and $4 million in 2013, which is included in Administrative and other expense in the consolidated statements of income. 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. The net impact to equity from the income tax payments, partially offset by the issuance of DERs, resulted in a charge to equity of $2 million in 2015, $1 million in 2014, and $2 million in 2013, which is not included in Administrative and other expenses in the consolidated statements of income.

As of December 31, 2015, unrecognized stock-based compensation expense was $6 million, of which approximately $4 million and $2 million is expected to be expensed in 2016 and 2017, 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, 2015, 2014, or 2013.

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,		
	2015	2014	2013
Weighted average common shares outstanding—basic	84,180	78,180	76,821
Dilutive effect of potential common shares	161	2,314	567
Weighted average common shares outstanding—diluted	84,341	80,494	77,388

NOTE 15: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2015, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2016	2017	2018	2019	2020	Thereafter	Total
Capital and other purchase commitments	$ 85	$ 2	$ 2	$ 2	$ 9	$ 27	$ 127
Purchased power and fuel:							
Electricity purchases	226	204	147	150	190	852	1,769
Capacity contracts	26	6	6	5	4	16	63
Public utility districts	6	5	5	1	1	12	30
Natural gas	67	41	38	37	32	221	436
Coal and transportation	14	11	5	5	—	—	35
Operating leases	10	10	9	7	6	180	222
Total	$ 434	$ 279	$ 212	$ 207	$ 242	$ 1,308	$ 2,682

Capital and other purchase commitments—Certain commitments have been made for 2016 and beyond that include those related to hydro licenses, upgrades to generating, 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 contracts with counterparties, which expire at varying dates through 2049, and power capacity contracts through 2024. In addition to the power purchase contracts with counterparties presented in the table, PGE has power sale contracts with counterparties of approximately $33 million that settle as follows: $15 million in 2016; $11 million in 2017, and $7 million in 2018.

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, 2015	PGE's Share as of December 31, 2015		Contract Expiration	PGE Cost, including Debt Service		
		Output	Capacity		2015	2014	2013
			(in MW)				
Priest Rapids and Wanapum	$ 1,191	8.6%	163	2052	$ 18	$ 14	$ 14
Wells	207	19.4	150	2018	10	10	10
Portland Hydro	2	100.0	36	2017	2	4	4

The agreements for Priest Rapids and 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 outstanding debt.

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. In addition to the gas purchase contracts with counterparties presented in the table, PGE has gas sale contracts with counterparties of approximately $2 million that settle in 2016. The Company also has a natural gas storage agreement for the purpose of fueling the Company's natural gas-fired generating plants (Port Westward Unit 1 (PW1), PW2, and Beaver).

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

Operating leases—PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities. The majority of the future minimum operating lease payments presented in the table consist of: i) the corporate headquarters lease, which expires in 2018, but includes renewal period options through 2043; and ii) 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 2015, $11 million in 2014, and $9 million in 2013.

The future minimum operating lease payments presented is net of sublease income of: $4 million in 2016; and $3 million in each of 2017, 2018, 2019 and 2020. Sublease income was $3 million in 2015, 2014 and 2013, respectively.

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, 2015, 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: VARIABLE INTEREST ENTITIES

PGE has determined that as of December 31, 2015 it is the primary beneficiary of a VIE (two as of December 31, 2014), and, therefore, consolidates the VIE within the Company's consolidated financial statements. The entity was formed for the sole purpose of designing, developing, constructing, owning, maintaining, operating, and financing photovoltaic solar power facilities located on real property owned by third parties, and selling the energy generated by the facilities. The Company is the Managing Member and a financial institution is the Investor Member in the Limited Liability Company (LLC), holding equity interests of less than 1% and more than 99%, respectively, in the entity. PGE has determined that its interest in this VIE contains the obligation to absorb the variability of the entity that could potentially be significant to the VIE, and the Company has the power to direct the activities that most significantly affect the entity's economic performance.

Determining whether PGE is the primary beneficiary of a VIE is complex, subjective, and requires the use of judgments and assumptions. Significant judgments and assumptions made by PGE in determining that it is the primary beneficiary of this LLC include the following: i) PGE has the experience to own and operate electric generating facilities and is authorized to operate the LLC pursuant to the operating agreement, and, therefore, PGE has control over the most significant activities of the LLC; ii) PGE expects to own 100% of the LLC shortly after five years have elapsed from when the facility was placed in service, at which time the facility will have approximately 75% of its estimated useful life remaining; and iii) based on projections prepared in accordance with the operating agreement, PGE expects to absorb a majority of any expected losses of the LLC.

Included in PGE's consolidated balance sheets as of December 31, 2015 and 2014 are LLC net assets of $3 million and $4 million, respectively, primarily comprised of Electric utility plant. These assets can only be used to settle the obligations of the consolidated VIE and its creditors have no recourse to the general credit of PGE.

In January 2016, PGE acquired the equity interest held by the Investor Member of the LLC pursuant to the terms of the operating agreement. The transaction did not have a significant impact to the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

NOTE 17: JOINTLY-OWNED PLANT

PGE has interests in three jointly-owned generating facilities. Under the joint operating agreements, 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.

In 1985, PGE sold a 15% undivided interest in Boardman and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. PGE assumed responsibility for the ARO related to that 15% interest in Boardman in the amount of $7 million. The acquisition of the 15% interest in Boardman increased the Company's ownership share from 65% to 80% on December 31, 2013. Such transaction is non-cash and is excluded from investing activities in the consolidated statement of cash flows for the year ended December 31, 2013.

On December 31, 2014, PGE acquired an additional 10% interest in Boardman from another co-owner, whereby the Company received net cash of $8 million from the co-owner to assume the net liabilities associated with the ownership of this 10% interest. In connection with this transaction, PGE recorded Electric utility plant of $7 million, inventory of $4 million, an ARO of $7 million, a regulatory liability of $6 million to be returned to customers over a two year period that began in 2015, a regulatory liability of $4 million related to future additional decommissioning and environmental costs, and deferred revenue of $2 million. The acquisition of the 10% interest in Boardman increased the Company's ownership share from 80% to 90%.

As of December 31, 2015, 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	$ 512	$ 375	$ —
Colstrip	20.00	1986	519	337	4
Pelton/Round Butte	66.67	1958 / 1964	244	58	5
Total			$ 1,275	$ 770	$ 9

* Excludes AROs and accumulated asset retirement removal costs.

NOTE 18: 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.

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. PGE has filed a motion for summary judgment dismissing the lawsuits. On July 27, 2015, the Circuit Court heard oral argument on the Company's motion for Summary Judgment. The court has yet to issue a decision on the motion. Following oral argument on PGE's motion for summary judgment, the plaintiffs moved to amend the complaints. PGE opposed the request to amend and the Court has not yet issued its decision.

PGE believes that the October 2014 OSC decision has 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 pending, 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 CERS filed a request for rehearing on February 1, 2016.

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 a January 2016 revised initial decision has now recommended that certain contracts by such respondent be subject to refund.

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 have not fully eliminated 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.” However, the remaining respondent subject to the revised initial decision has stated on the record that it will not pursue ripple claims, and on February 1, 2016, the Acting Chief Administrative Law Judge issued an order holding that the issue of ripple claims is terminated for purposes of Phase II of these proceedings. Therefore, unless the current FERC orders are overturned or modified on appeal, the Company does not believe that it will incur any material loss in connection with this matter.

Management cannot predict the outcome of the various pending appeals and remands concerning this matter. If, on rehearing, appeal, or subsequent remand, the Ninth Circuit or the FERC were to reverse previous FERC rulings on liability or find that a market-wide remedy is appropriate, it is possible that additional refund claims could be asserted against the Company. However, management cannot predict, under such circumstances, which contracts would be subject to refunds, the basis on which refunds would be ordered, or how such refunds, if any, would be calculated. Further, management cannot predict whether any current respondents, if ordered to make refunds, would pursue additional refund claims against their suppliers, and, if so, what the basis or amounts of such potential refund claims against the Company would be. Due to these uncertainties, sufficient information is currently not available to determine PGE’s liability, if any, or to estimate a range of reasonably possible loss.

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 January 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 is currently undergoing a remedial investigation (RI) and feasibility study (FS) 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.

In March 2012, the LWG submitted a draft FS to the EPA for review and approval. In August 2015, the EPA substantially revised the draft FS as submitted by the LWG and issued its own draft FS which is currently in the process of undergoing further consideration and comment. The draft FS, along with the RI, is expected to provide the framework for the EPA to determine a clean-up remedy for Portland Harbor that will be documented in a Record of Decision (ROD).

The EPA's draft FS evaluates several alternative clean-up approaches, which would take from four to 18 years with the present value of estimated costs ranging from $800 million to $2.4 billion, depending on the selected remedial action levels and the choice of remedy. While the revised draft FS aids in the development of a proposed plan to remediate Portland Harbor, the draft FS does not address responsibility for the costs of clean-up, allocate such costs among PRPs, or define precise boundaries for the clean-up. In November 2015, the EPA proposed its preferred alternative remedy to the National Remedy Review Board (NRRB) for comment. The EPA's preferred alternative has an estimated present value cost of $1.5 billion and would take approximately seven years to complete. The EPA anticipates it will release, for public review and comment, a Proposed Cleanup Plan in the Spring of 2016. The Company currently expects the EPA to issue a determination of its preferred remedy in a final ROD in late 2016, however responsibility for funding and implementing the EPA's selected remedy is not expected to be known for some time. PGE is participating in a voluntary process to establish and develop allocation of costs.

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 is 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. It is uncertain what portion, if any, PGE may be held responsible related to Portland Harbor.

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 agreement of allocation of costs amongst PRPs. Although it is probable that the Company's share of these costs could be material, 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 and NRDA. The Company plans to seek recovery of any costs resulting from the Portland Harbor proceeding through regulatory recovery in customer prices and through claims under insurance policies.

Alleged Violation of Environmental Regulations at Colstrip

In July 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the Clean Air Act (CAA) at Colstrip Steam Electric Station (CSES) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other CSES co-owners, including Talen Montana, LLC, the operator of CSES. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The Notice alleges certain violations of the CAA, including New Source Review, Title V, and opacity requirements, and stated that the Sierra Club and MEIC would: i) request a United States District Court to impose injunctive relief and civil penalties; ii) require a beneficial environmental project in the areas affected by the alleged air pollution; and iii) seek reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees.

The Sierra Club and MEIC asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and that the owners have violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality (MDEQ). The Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

On March 6, 2013, the Sierra Club and MEIC sued the CSES co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs are seeking relief that includes an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter.

In May 2013, the defendants filed a motion to dismiss 36 of 39 claims alleged in the complaint. In September 2013, the plaintiffs filed a motion for partial summary judgment regarding the appropriate method of calculating emissions increases. Also in September 2013, the plaintiffs filed an amended complaint that withdrew Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects. In July 2014, the court denied the defendants' motion to dismiss and the plaintiffs' motion for partial summary judgment.

In August 2014, the plaintiffs filed a second amended complaint to which the defendants' response was filed in September 2014. The second amended complaint continues to seek injunctive relief, declaratory relief, and civil penalties for alleged violations of the federal Clean Air Act. The plaintiffs state in the second amended complaint that it was filed, in part, to comply with the court's ruling on the defendants' motion to dismiss and plaintiffs' motion for partial summary judgment. Discovery in this matter is complete. The parties filed various summary judgment motions during the summer of 2015. Oral argument on those motions occurred on December 1, 2015. On or about December 31, 2015, the Magistrate Judge issued Findings and Recommendations that, if adopted by the trial court, would result in dismissal of several of the plaintiffs' claims. The case is currently set for trial on May 6, 2016.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome, estimate a range of potential loss, or determine whether it would have a material impact on the Company.

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)			
2015				
Revenues, net	$ 473	$ 450	$ 476	$ 499
Income from operations	85	72	68	84
Net income	50	35	36	51
Net income attributable to Portland General Electric Company	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
2014				
Revenues, net	$ 493	$ 423	$ 484	$ 500
Income (loss) from operations	98	58	65	72
Net income (loss)	58	35	38	43
Net income (loss) attributable to Portland General Electric Company	58	35	39	43
Earnings per share: *				
Basic	0.74	0.44	0.48	$ 0.57
Diluted	0.73	0.43	0.47	$ 0.55

* 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, 2015, the Company’s internal control over financial reporting is effective.

The Company’s internal control over financial reporting, as of December 31, 2015, 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, 2015.

(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 2015 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

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 27, 2016.

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 27, 2016.

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 27, 2016.

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 27, 2016.

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 27, 2016.

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*	Confirmation of Forward Sale Transaction dated June 11, 2013 between Portland General Electric Company and Barclays Bank PLC (Form 8-K filed June 17, 2013, Exhibit 10.1).
10.3*	First Amendment to Confirmation Agreement dated June 25, 2013 between Portland General Electric Company and Barclays Bank PLC (Form 10-Q filed August 2, 2013, Exhibit 10.2).
10.4*	Transfer Agreement between BA Leasing BSC, LLC, as Transferor, and Portland General Electric Company, as Transferee, dated December 18, 2013 (Form 10-K filed February 14, 2014, Exhibit 10.8).
10.5*	Portland General Electric Company Severance Pay Plan for Executive Employees dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.1) (File No. 001-05532-99). +
10.6*	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). +
10.7*	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). +
10.8*	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). +
10.9*	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). +
10.10*	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). +
10.11*	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). +
10.12*	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). +
10.13*	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). +
10.14*	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). +
10.15*	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). +
10.16*	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). +
10.17*	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). +
10.18*	Form of Directors' Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.19*	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.

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 11, 2016.

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 11, 2016.

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 12.1

PORTLAND GENERAL ELECTRIC COMPANY

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(Dollars in thousands)

	Years Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Income from continuing operations before income taxes	$ 216,818	$ 236,679	$ 125,758	$ 205,406	$ 204,714
Total fixed charges	135,956	128,515	118,189	122,851	126,766
Total earnings	$ 352,774	$ 365,194	$ 243,947	$ 328,257	$ 331,480
Fixed charges:					
Interest expense	$ 113,861	$ 96,068	$ 100,818	$ 107,992	$ 110,413
Capitalized interest	12,520	22,441	6,892	3,699	3,059
Interest on certain long-term power contracts	5,140	5,137	5,996	6,643	8,764
Estimated interest factor in rental expense	4,435	4,869	4,483	4,517	4,530
Total fixed charges	$ 135,956	$ 128,515	$ 118,189	$ 122,851	$ 126,766
Ratio of earnings to fixed charges	2.59	2.84	2.06	2.67	2.61

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-192274 on Form S-3 and Registration Statements Nos. 333-135726, 333-142694, and 333-158059 on Forms S-8 of our report dated February 11, 2016, 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, 2015.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 11, 2016

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 11, 2016

/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 11, 2016

/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, 2015, as filed with the Securities and Exchange Commission on February 12, 2016 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 11, 2016	Date: February 11, 2016