PORTLAND GENERAL ELECTRIC CO /OR/
Form 10-K
February 12, 2016

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

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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.

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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

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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.

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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.

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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.

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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.”

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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.

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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.

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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.

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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.

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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

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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.

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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,

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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."

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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

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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

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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.

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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.

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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.

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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.

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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.

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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.

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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

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(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 i 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;

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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

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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.

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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.

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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 Average Number of Customers	Energy Deliveries *	2014 Average Number of Customers	Energy Deliveries *	Increase/ (Decrease) in 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

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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

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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.

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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.

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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	%

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

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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.

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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.

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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.

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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:

Location	Runoff as a Percent of Normal *					
	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.

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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:

Location	Runoff as a Percent of Normal *	
	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.

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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.

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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.

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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

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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.

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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	$	