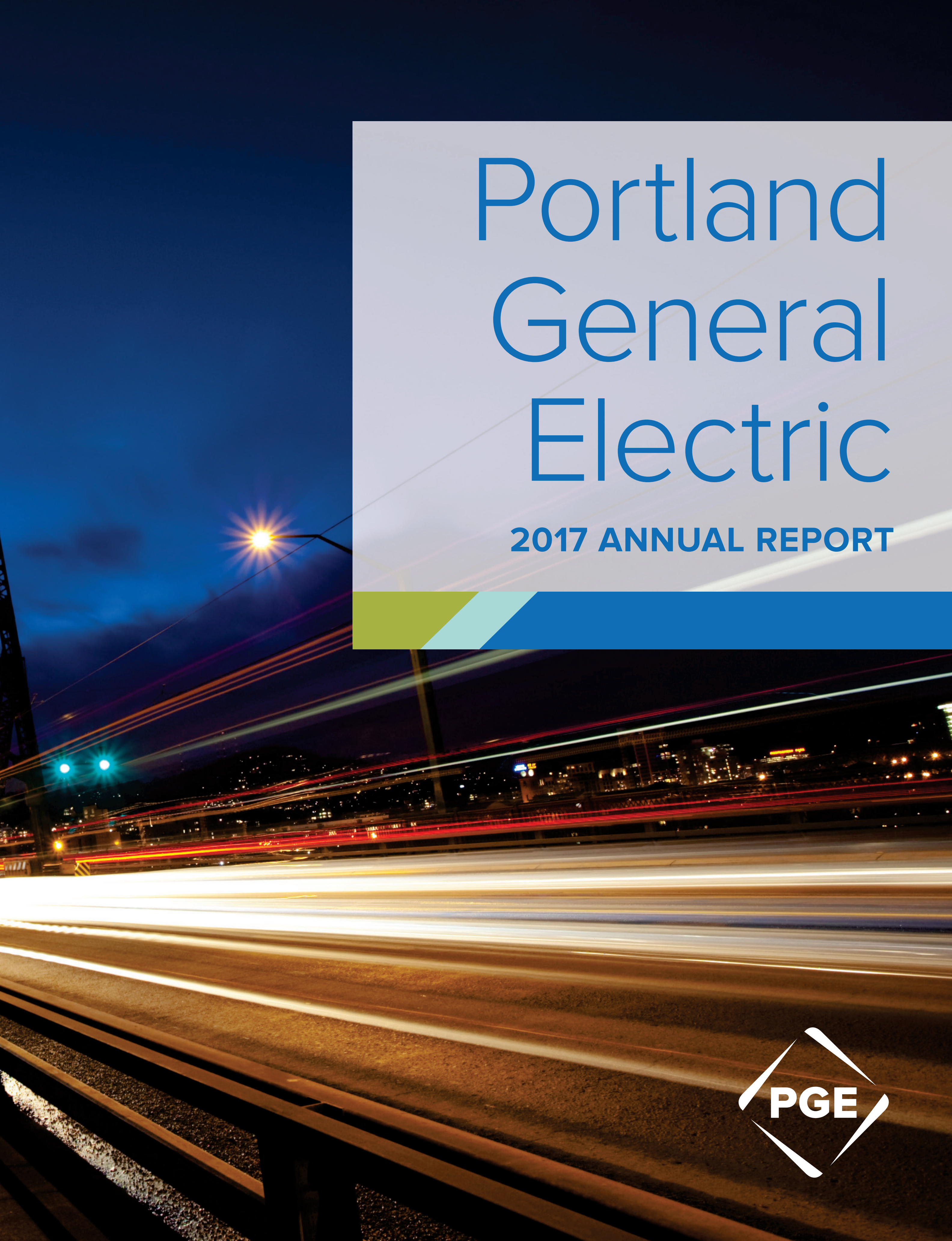
Portland General Electric

2017 ANNUAL REPORT



To our shareholders:

Oregonians are at the forefront of a dramatic transformation to a clean energy future, spurred by technological advancements and changing customer expectations. I am excited about the opportunities ahead as PGE delivers clean energy solutions, equitably and seamlessly, through integrated, secure, smart energy infrastructure.

At PGE, our strong operating performance combined with our solid track record of safe, reliable, affordable, clean and secure energy delivery is building long-term value for all of our stakeholders.

We delivered a solid performance in 2017 with a non-GAAP net income of $204 million, or $2.29 per diluted share, after excluding the impacts of the recent tax reform[1]. This is a 6.0 percent increase over the prior year. Stock appreciation for the year — in combination with the quarterly dividends, which we increased from $0.32 per share to $0.34 per share — provided shareholders a total return of 8.3 percent.

OPERATIONAL ACHIEVEMENTS

Our customers continue to rate us among the top-performing utilities in the nation for satisfaction, including top-decile rankings from our key customers and top-quartile rankings from residential and business customers[2].

In 2017, we successfully transitioned to the western Energy Imbalance Market, which optimizes the use of our region's resources reliably and cost-efficiently. Other achievements included the satisfactory conclusion of our 2018 General Rate Case and regulatory acknowledgement of our Integrated Resource Plan, including running an RFP to acquire up to 100 average megawatts of qualifying renewable resources.

PGE's $514 million in capital expenditures in 2017 demonstrates our ongoing commitment to building a more reliable and resilient grid. To maintain and improve our 99.98 percent reliability achieved in 2017 and accommodate the rapid growth in our region, we made significant progress on replacing and upgrading aging equipment, improving cyber and physical security and adding earthquake resiliency.

Our region is thriving, and we will continue to collaborate with state, regional and local partners to advance economic development. Oregon boasts one of the nation's highest levels of GDP growth, and unemployment rates in 2017 averaged 4 percent — the lowest full-year rate on record for the state. This translated to nearly 12,000 new customers, a 1.3 percent increase over last year.

PGE's 2,900 dedicated employees are working together to deliver outstanding value to our customers. I'm especially proud of all we do to help make Oregon a better place by volunteering our time and resources in our communities. Employees, retirees and the company donated $2.2 million

1. Net income of $187 million or $2.10 per diluted share when including the impacts of the recent federal Tax Cuts and Jobs Act
2. Market Strategies International and TQS Research, Inc.

through our employee matching-gift program and volunteered more than 45,000 hours in 2017. Also during the year, PGE and the PGE Foundation invested more than $2 million in programs and events that help improve the quality of life for Oregonians.

LOOKING FORWARD

I am privileged to serve as CEO of Oregon's largest energy utility and congratulate Jim Piro on his retirement. During his nine years as CEO, PGE consistently delivered top-quartile performance for both customer satisfaction and system reliability. Investments in our systems and new generation resources have increased power supply reliability and reduced price volatility, while also doubling the value of PGE shares and contributed to 11 consecutive years of annual dividend growth.

Our long-term strategy builds on this strong foundation. This includes additional investments in a smarter, more resilient energy infrastructure that will enhance reliability and allow us to more effectively integrate an ever-growing array of clean and renewable energy resources.

I would like to thank my colleagues who are dedicated to powering our customers' lives every day while embracing the opportunities ahead. Together, we are well positioned to lead our region through this energy transformation.

Maria M. Pope

Maria M. Pope
President and Chief Executive Officer

A SMARTER, MORE INTERCONNECTED WESTERN ENERGY GRID

We entered the western Energy Imbalance Market in 2017 and became part of an automated system that integrates electricity generation across six states. With this important step, we're better integrating renewable energy, managing the variations of our customers' load and capturing the most cost-effective resources as we continue to invest in clean and reliable energy for our customers.

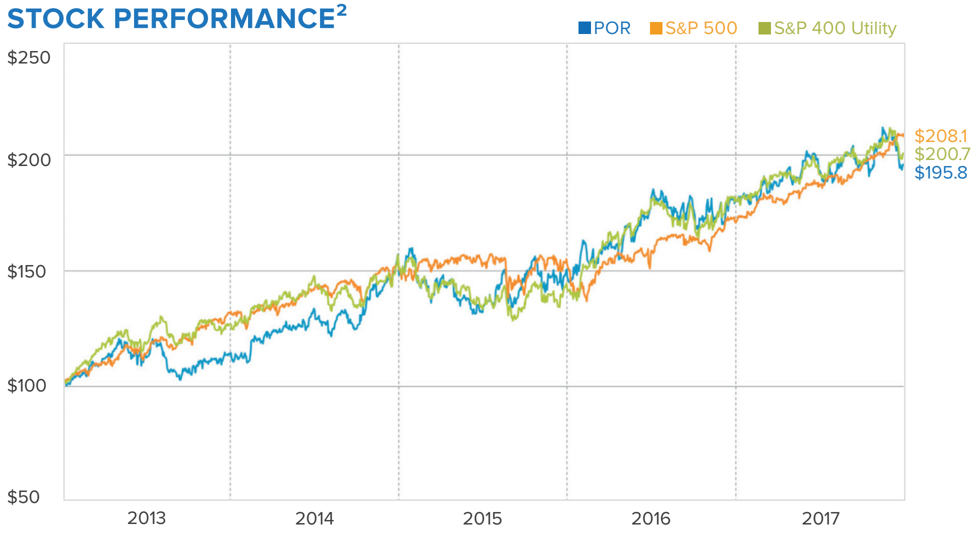
Financial Highlights

ABOUT PORTLAND GENERAL ELECTRIC

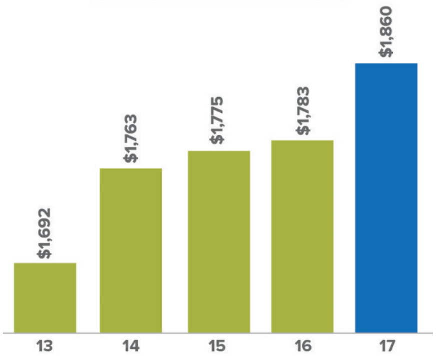
Portland General Electric Company, headquartered in Portland, Ore., is a fully integrated electric utility serving approximately 875,000 residential, commercial and industrial customers in Oregon. We have been powering Oregon for more than 125 years. PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR.

(Dollars in millions, except per share amounts)	2017	2016	2015
Operating revenues	$2,009	$1,923	$1,898
Net operating income	$376	$333	$309
Net income for common stock	$187[1]	$193	$172
Earnings per share, diluted	$2.10[1]	$2.16	$2.04
Return on average equity	7.9%	8.4%	8.3%
Dividends declared per common share	$1.34	$1.26	$1.18
Weighted-average shares outstanding (in thousands), diluted	89,176	89,054	84,341
FOLLOWING DATA AS OF YEAR-END			
Total assets	$7,838	$7,527	$7,210
Long-term debt, including current portion	$2,426	$2,350	$2,193
Long-term debt/capitalization	50.6%	50.6%	49.3%
Senior secured debt ratings (S&P/Moody's)	A-/A1	A-/A1	A-/A1
Commercial paper ratings (S&P/Moody's)	A-2/P-2	A-2/P-2	A-2/P-2
Customers	875,000	863,000	852,000
Employees	2,906	2,752	2,646

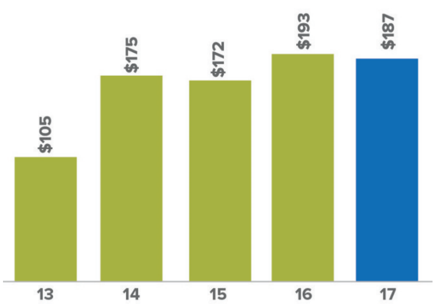
STOCK PERFORMANCE[2]



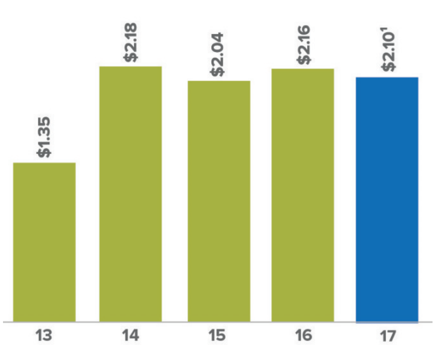
TOTAL RETAIL REVENUE



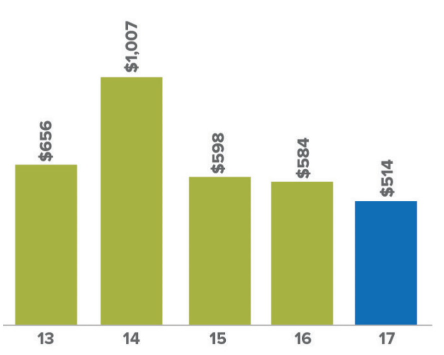
NET INCOME



EARNINGS PER SHARE (DILUTED)



CAPITAL EXPENDITURES



1. Non-GAAP net income and diluted earnings per share excluding the effects of the federal Tax Cuts and Jobs Act were $204 million and $2.29 respectively.
2. The chart above assumes a $100 investment in Portland General Electric's common stock and each index on Dec. 31, 2012, and that all dividends were reinvested.

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, 2017

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 Data 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, a smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	[x]		Accelerated filer	[ ]
Non-accelerated filer	[ ]	(Do not check if a smaller reporting company)		
			Smaller reporting company	[ ]
			Emerging growth company	[ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

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, 2017, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $4,048,647,464. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 2, 2018, there were 89,114,522 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 25, 2018.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2017

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DEFINITIONS

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

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

PART I

ITEM 1. BUSINESS.

General

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

PGE's state-approved service area allocation of approximately 4,000 square miles is located entirely within Oregon and includes 51 incorporated cities, of which Portland and Salem are the largest. The Company estimates that at the end of 2017 its service area population was 1.9 million, comprising approximately 46% of the population of the State of Oregon. During 2017, the Company added nearly 12,000 customers and as of December 31, 2017, served a total of 875,000 retail customers.

PGE had 2,906 employees as of December 31, 2017, with 785 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 732 and 53 employees and expire March 2020 and August 2022, respectively.

Available Information

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

Regulation

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

Federal Regulation

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

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

Wholesale Energy—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA). The BAA is the area in which PGE is responsible for balancing customer demand with electricity generation, in real time. Continued market-based rate authority requires specific actions by PGE including the filing of triennial market power studies with the FERC, the filing of notices of change in status, and compliance with FERC rules. In May 2017, PGE filed with the FERC proposed revisions to its market-based rate tariff to reflect its participation in the California Independent System Operator's (CAISO) Energy Imbalance Market (western EIM). In June 2017, PGE separately filed with the FERC a Notice of Change in Status requesting authorization to trade at market-based rates in that market.

On September 28, 2017, the FERC issued an Order accepting both of these filings and authorizing PGE to transact at market-based rates in the western EIM. On August 30, 2017, CAISO filed with the FERC an Informational Readiness Certification for PGE's participation in the western EIM, which began on October 1, 2017. The entry into the western EIM does not change PGE's restriction on non-EIM sales at market-based rates within its BAA, which restriction does not have a material impact on the Company. For further information on the western EIM, see "Purchased Power" in the Power Supply section of this Item 1.

Transmission—PGE offers electricity transmission service pursuant to its Open Access Transmission Tariff (OATT), which contains rates and terms and conditions of service, as filed with, and approved by the FERC. As required by the OATT, PGE provides information regarding its electric transmission business on its Open Access Same-time Information System, also known as OASIS. In PGE's Notice of Change in Status filed with the FERC on June 16, 2017, PGE stated that inbound western EIM transfers would take place on certain paths upon which the Company holds firm transmission rights, a portion of which it has committed for western EIM transfers. In the FERC's September 28, 2017 Order accepting this filing, the FERC ordered PGE to submit a change in status filing if there were to be a decrease in the amount of firm transmission capacity committed to western EIM transfers. For additional information, see the Transmission and Distribution section in this Item 1. and Item 2.—"Properties."

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

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

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

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

Short-term Debt—Pursuant to applicable provisions of the FPA and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. The Company, pursuant to an order issued by the FERC on January 3, 2018, has authorization to issue up to $900 million of short-term debt through February 6, 2020.

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

State of Oregon Regulation

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

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

Economic Regulation—Under Oregon law, the OPUC is required to ensure that prices and terms of service are fair and non-discriminatory, and to 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. For additional information regarding the Company's most recent general rate cases, see "*General Rate Cases*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

- *Power Costs*. In addition to price changes resulting from the general rate case process, the OPUC has approved the following mechanisms by which PGE can adjust retail customer prices to cover changes in the Company's net variable power costs (NVPC). NVPC consists of the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Company's consolidated statements of income) and is net of wholesale revenues, which are classified as Revenues, net in the condensed consolidated statements of income.
    - Annual Power Cost Update Tariff (AUT). Under this tariff, customer prices are adjusted annually to reflect forecasted NVPC. An initial NVPC forecast, submitted to the OPUC by April 1 each year, is updated during such year and finalized in November. Based upon the final forecast, new prices, as approved by the OPUC, become effective at the beginning of the following calendar year; and
    - Power Cost Adjustment Mechanism (PCAM). Under the PCAM, PGE shares a portion of the business risk or benefit associated with NVPC. Customer prices can be adjusted annually to absorb a portion of the difference between the forecasted NVPC included in customer prices (baseline NVPC) and actual NVPC for the year. 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."
- *Renewable Energy.* The 2007 Oregon Renewable Energy Act (the 2007 Act) established a Renewable Portfolio Standard (RPS), which required that PGE serve at least 15% of its retail load with renewable resources by 2015, with future requirements of 20% by 2020 and 25% by 2025. PGE met the 2015 requirement and expects to meet the requirements going forward.

  The 2007 Act allows renewable energy certificates (RECs), 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 2007 Act also provides for the recovery in customer prices of prudently incurred costs 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 1 of each year for new renewable resources expected to be placed in service in the current year, with prices expected to become effective January 1 of the following year. In addition, the RAC provides for the deferral and subsequent recovery of eligible costs incurred prior to January 1 of the following year.

  Under the RAC, the Company has submitted no material additions or deferrals for the three years 2015 through 2017.

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

  For more information regarding the OCEP, and its impact on PGE, see the "*Legal, Regulatory, and Environmental Matters*" section of Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations.
- *Decoupling.* The decoupling mechanism provides a means for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts undertaken by residential and certain commercial customers. The mechanism, authorized by the OPUC through 2019,

provides for: i) collections from customers if weather-adjusted energy use per customer is lower than levels anticipated in the Company's most recent general rate case; or ii) refunds to customers if weather-adjusted use per customer exceeds levels anticipated in the most recent general rate case. For additional information, see *"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 on the RAC, the OCEP, and other ratemaking proceedings, see the *"Legal, Regulatory, and Environmental Matters"* discussion in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Senate Bill 978—The State of Oregon legislature passed a bill in its 2017 session referred to as SB 978, which directs the OPUC to investigate and provide a report to the legislature by September 15, 2018 on how developing industry trends, technology, and policy drivers in the electricity sector might impact the existing regulatory system and incentives. PGE is actively working on this initiative, both internally and in conjunction with the OPUC, to provide input and support development of the report. The OPUC recently opened a proceeding to collect input on possible changes to the regulatory model from stakeholders including regulated utilities such as PGE.

Integrated Resource Plan—Unless the OPUC grants an extension, PGE is required to file an Integrated Resource Plan (IRP) with the OPUC within two years of its previous IRP acknowledgment order. The IRP guides the utility on a plan to meet future customer demand and describes the Company's future energy supply strategy, which reflects new technologies, market conditions, and regulatory requirements. The primary goal of the IRP is to identify a portfolio of generation, transmission, demand-side, and energy efficiency resources that, along with the Company's existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for PGE and its customers. For additional information on PGE's 2016 IRP, see "Integrated Resource Plans" in the Overview section in this 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 daily market index-based pricing, and Direct Access, whereby customers purchase their electricity from an Electricity Service Supplier (ESS). All commercial and industrial customers are eligible for Direct Access, under which the Company receives revenue only for the transmission and delivery of the energy to the ESS customers, while only certain large commercial and industrial customers may elect to be served by PGE on a daily market index-based price.

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

The retail customer choice program does not have a material impact on PGE'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 PGE. 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. For further information regarding Direct Access deliveries, see *"Customers and Demand"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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

Energy Efficiency Funding—Oregon law provides for a public purpose charge to fund cost-effective energy efficiency measures, new renewable energy resources, and weatherization measures for low-income housing. This charge, equal to 3% of retail revenues, is collected from customers and remitted to the ETO and other agencies for administration of these programs. The Company collected $53 million from customers for this charge in 2017, $50 million in 2016, and $51 million in 2015.

In addition to the public purpose charge, PGE also remits to the ETO amounts collected from its customers under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. This charge was 3.6%, 2.7%, and 2.4% of retail revenues for applicable customers in 2017, 2016, and 2015, respectively. Under the tariff, $66 million, $48 million, and $42 million were collected from eligible customers in 2017, 2016, and 2015, respectively.

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

Regulatory Accounting

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

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

Customers and Revenues

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

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 6% of PGE's total retail revenues or 9% of total retail deliveries. While the twenty largest commercial and industrial customers constituted 11% of total retail revenues in 2017, they represented nine different groups including high tech, paper manufacturing, governmental agencies, health services, and retailers.

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

	Years Ended December 31,					
	2017		2016		2015	
Retail revenues[1] (dollars in millions):						
Residential	$ 969	52%	$ 907	51%	$ 895	50%
Commercial	669	36	665	37	662	37
Industrial	212	11	208	12	228	13
Subtotal	1,850	99	1,780	100	1,785	100
Other accrued (deferred) revenues, net	10	1	3	—	(10)	—
Total retail revenues	$ 1,860	100%	$ 1,783	100%	$ 1,775	100%
Retail energy deliveries[2] (MWh in thousands):						
Residential	7,880	40%	7,348	39%	7,325	38%
Commercial	7,555	38	7,457	39	7,511	39
Industrial	4,283	22	4,166	22	4,546	23
Total retail energy deliveries	19,718	100%	18,971	100%	19,382	100%
Average number of retail customers:						
Residential	762,211	88%	752,365	88%	742,467	88%
Commercial	107,855	12	106,773	12	105,802	12
Industrial	267	—	258	—	255	—
Total	870,333	100%	859,396	100%	848,524	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,		
	2017	2016	2015
Residential			
Revenue per customer (in dollars):	$ 1,181	$ 1,114	$ 1,139
Usage per customer (in kilowatt hours):	10,338	9,766	9,866
Revenue per kilowatt hour (in cents):	11.42¢	11.40¢	11.55¢
Commercial			
Revenue per customer (in dollars):	$ 6,142	$ 6,166	$ 6,254
Usage per customer (in kilowatt hours):	70,046	69,839	70,987
Revenue per kilowatt hour (in cents):	8.77¢	8.83¢	8.81¢
Industrial			
Revenue per customer (in dollars):	$ 792,466	$ 804,953	$ 876,866
Usage per customer (in kilowatt hours):	16,041,461	16,146,371	17,485,281
Revenue per kilowatt hour (in cents):	4.94¢	4.99¢	5.01¢

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, summer peaks have exceeded winter peaks and long-term load forecasts expect that trend to continue. Economic conditions can also affect residential demand; strong job growth and population growth in PGE's service territory have led to increasing customer growth rates. Residential demand is also impacted by energy efficiency measures; however, the Company's decoupling mechanism is intended to mitigate the financial effects of such measures.

During 2017, total residential deliveries increased 7.2% compared with 2016. PGE witnessed a 1.3% increase in the average number of residential customers served during the year and average usage per customer increased 5.9% driven by favorable weather compared to the prior year. Temperatures in 2017 were characterized by both a cold heating season in the first quarter and a warm cooling season over the summer months, increasing residential energy deliveries. The year-over-year impact was intensified by unseasonably warm heating season temperatures seen in 2016, which decreased residential energy deliveries in that year. On a weather-adjusted basis, energy deliveries to residential customers decreased by 2.2% in 2017 when compared with 2016.

During 2016, residential customer count increased by 1.3%, however the summer cooling season was not as extreme as experienced in 2015 leading to a decrease in average use per customer of 1.0%. The overall result was that total residential energy deliveries increased 0.3% in 2016 compared with 2015. On a weather-adjusted basis, energy deliveries to residential customers increased by 1.4% in 2016 when compared with 2015.

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 affect commercial demand to some extent. Economic conditions and fluctuations in total employment in the region can also lead to changes in energy demand from commercial customers. Energy efficiency measures also impact commercial demand, although the Company's decoupling mechanism partially mitigates the financial effects of such measures.

In 2017, a 1.0% growth in the average number of commercial customers and a cold first quarter heating season drove a 1.3% increase in commercial deliveries compared with 2016. Weather-adjusted, deliveries to commercial customers decreased by 0.7% in 2017. Deliveries to several retail sectors decreased, including food and merchandise stores and office, finance, insurance, and real estate. These decreases were only partially offset by increases in the miscellaneous and other services sectors, which are driven by a strong construction cycle and data center growth. Energy efficiency continues to impact growth, and conservation and building codes and standards are likely reducing energy deliveries beyond the impact of energy efficiency programs.

Deliveries to commercial customers decreased 0.7% in 2016 compared with 2015, which was primarily due to unfavorable weather conditions and slightly lower demand from a few groups, including food stores, which were impacted by a series of mergers and bankruptcies, government and education, and irrigation and pumping load in 2016 due to the extremely dry conditions that existed in 2015. On a weather-adjusted basis, commercial deliveries for 2016 were comparable to 2015, while a 0.9% increase in the average number of commercial customers occurred.

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 2.8% in 2017 from 2016, reflecting increases across several manufacturing sectors, with the strongest increases to customers in high tech manufacturing and their suppliers. These increases were largely offset by the closure of a large paper manufacturing customer that ceased operations in October 2017.

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

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

Wholesale Revenues

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

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

Other Operating Revenues

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

Seasonality

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

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

	Heating Degree-Days	Cooling Degree-Days
2017	4,558	700
2016	3,552	548
2015	3,461	785
15-year average	4,233	471

PGE's all-time high net system load peak of 4,073 megawatts (MW) occurred in December 1998. The Company's all-time summer peak of 3,976 MW occurred in August 2017. The following table presents PGE's average winter (defined as January, February, and December) and summer (defined as July, August, and September) loads for the periods presented, along with the corresponding peak load (in MWs) and month in which such peak occurred. As the table below illustrates, although the average winter loads continue to run higher than average summer loads, the Company has experienced its highest peak loads during summer in each of the past three years:

	Winter Loads			Summer Loads		
	Average	**Peak**	**Month**	**Average**	**Peak**	**Month**
2017	2,698	3,727	January	2,380	3,976	August
2016	2,537	3,716	December	2,246	3,726	August
2015	2,509	3,255	December	2,390	3,914	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 seven thermal plants (natural gas- and coal-fired), two wind farms, and seven hydroelectric facilities. Capacity of the thermal plants represents the MW the plant is capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant. Capacity of both hydro and wind generating resources represent the nameplate MW, which varies from actual energy expected to be received as these types of generating resources are highly dependent upon river flows and wind conditions, respectively. Availability represents the percentage of the year the plant was available for operations, which reflects the impact of planned and forced outages. For a complete listing of these facilities, see "*Generating Facilities*" in Item 2.—"Properties."

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

	As of December 31,					
	2017		2016		2015	
	Capacity	%	Capacity	%	Capacity	%
Generation:						
Thermal:						
Natural gas	1,831	39%	1,805	38%	1,371	30%
Coal	814	17	814	17	814	17
Total thermal	2,645	56	2,619	55	2,185	47
Wind (1)	717	15	717	15	717	16
Hydro (2)	495	10	495	11	495	11
Total generation	3,857	81	3,831	81	3,397	74
Purchased power:						
Long-term contracts:						
Capacity/exchange	100	2	250	5	250	5
Hydro	531	12	534	12	592	13
Wind	39	1	39	1	39	1
Solar	13	—	13	—	13	—
Other	18	—	18	—	118	3
Total long-term contracts	701	15	854	18	1,012	22
Short-term contracts	185	4	45	1	200	4
Total purchased power	886	19	899	19	1,212	26
Total resource capacity	4,743	100%	4,730	100%	4,609	100%

(1) Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 215 MWa to 290 MWa, dependent upon wind conditions.

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

For information regarding actual generating output and purchases for the years ended December 31, 2017, 2016, and 2015, 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.

Thermal The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty. These natural gas-fired generating plants provided approximately 33% of PGE's total retail load requirement in 2017, 32% in 2016, and 25% in 2015.

The Company operates, and has a 90% ownership interest in 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 18% of the Company's total retail load requirement in 2017, compared with 19% in 2016, and 22% in 2015. Boardman is scheduled to cease coal-fired operations at the end of 2020, and pursuant to Oregon Senate Bill 1547, PGE's portion of Colstrip is scheduled to be fully depreciated by 2030, with the potential to utilize the output of the facility, in Oregon, until 2035. For additional information on Senate Bill 1547, see "*Legal, Regulatory,* *and Environmental Matters*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

The thermal plants provide reliable power and capacity reserves for PGE's customers. These resources have a combined capacity of 2,645 MW, representing approximately 69% of the net capacity of PGE's generating portfolio. Thermal plant availability, excluding Colstrip, was 88% in 2017, 92% in 2016, and 89% in 2015, while Colstrip availability was 86% in 2017, compared with 85% in 2016 and 93% in 2015.

Wind PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River Wind Farm (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 2017, 10% in 2016, and 9% in 2015. Availability for these resources was 96% in 2017, compared with 95% in 2016 and 97% in 2015. The expected energy from wind resources differs from the nameplate capacity and is expected to range from 135 MWa to 180 MWa for Biglow Canyon and from 80 MWa to 110 MWa for Tucannon River, dependent upon wind conditions.

Hydro The Company's FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. The licenses for these projects expire at various dates ranging from 2035 to 2055. Although these plants have a combined capacity of 495 MW, actual energy received is dependent upon river flows. Energy from these resources provided 9% of the Company's total retail load requirement in 2017, 9% in 2016, and 8% in 2015, with availability of 95% in 2017, and 99% in both 2016 and in 2015. Northwest hydro conditions have a significant impact on the region's power supply, with water conditions significantly impacting PGE's cost of power and its ability to economically displace more expensive thermal generation and spot market power purchases.

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

Dispatchable Standby Generation (DSG)—PGE has a DSG program under which the Company can start, operate, and monitor customer-owned diesel-fueled standby generators when needed to provide NERC-required operating reserves. As of December 31, 2017, there were 59 sites with a total DSG capacity of 123 MW. Additional DSG projects are being pursued with a total goal of 135 MW online by the end of 2021.

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

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

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

PGE also has contractual access to natural gas storage in Mist, Oregon from which it can draw as needed. The Company expects to utilize this resource when economic factors favor its use or in the event that natural gas supplies are interrupted. The storage facility is owned and operated by a local natural gas company, NW Natural, and may be utilized to provide fuel to PW1, PW2, and Beaver.

PGE has entered into a long-term agreement with this gas company to expand the current storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-mile pipeline, that will be designed to provide no-notice storage services to these PGE generating plants. Pursuant to the agreement, on September 30, 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which NW Natural estimates will be completed during the winter of 2018-2019, at a cost of approximately $132 million.

Beaver has the capability to operate on fuel oil when it is economical or if the plant's natural gas supply is interrupted. PGE had an approximate five day supply of ultra-low sulfur diesel fuel oil at the plant site as of December 31, 2017. The current operating permit for Beaver limits the number of gallons of fuel oil that can be burned daily, which effectively limits the daily hours of operation of Beaver on fuel oil.

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

Coal

PGE has fixed-price purchase agreements that, together with existing inventory, will provide coal sufficient for the anticipated operating needs for Boardman during 2018. The coal is obtained from surface mining operations in Wyoming and is delivered by rail under two separate transportation contracts which extend through 2020.

The terms of contracts and the quality of coal are expected to be staged in alignment with required emissions limits. PGE believes that sufficient market supplies of coal are available to meet anticipated coal-fired 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 continue negotiations to extend the contract.

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis. Such contracts have original terms ranging from one month to 39 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 one contract that provides the Company with firm capacity to help meet peak loads. The agreement allows for up to 100 MW of seasonal peaking capacity during winter periods through February 2019.

Hydro—During 2017, the Company had three contracts that provided for the purchase of power generated from hydroelectric projects with an aggregate capacity of 56 MW and contract expirations between 2018 and 2032. In addition, PGE has the following:

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

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

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

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

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

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

PGE began participating in the western EIM on October 1, 2017. As a market participant in the western EIM PGE allows certain of its generating plants to receive automated dispatch signals from the CAISO that allows for load balancing with other western EIM participants in five-minute intervals. The Company expects such load balancing will help integrate more renewable energy into the grid by better matching the variable output of renewable resources. Additionally, participation in the western EIM gives PGE access to the lowest-cost energy available in the region to meet changes in real-time energy loads and short-term variations in customer demand. The Company expects that participation in the western EIM will reduce costs for PGE customers.

Future Energy Resource Strategy

PGE's IRP outlines the Company's plan to meet future customer demand and describes PGE's future energy supply strategy. For a detailed discussion of the IRPs, see "Integrated Resource Plan" within the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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 2017, PGE delivered approximately 23 million MWh in its balancing authority area through 1,250 circuit miles of transmission lines operating at or above 115 kilovolts (kV).

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

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

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

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

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

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

Environmental Matters

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

Air Quality

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

To maintain compliance with the various air quality standards, PGE manages its air emissions at its thermal generating plants 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 emissions controls and the continued use of low sulfur fuel, are anticipated to be sufficient to permit the Company to meet its air emissions compliance requirements.

DEQ has initiated a rulemaking to overhaul its air toxic permit program for industrial sources. DEQ placed proposed rules on public notice and has accepted comments. PGE is evaluating potential impacts the proposed regulations could have on its thermal generating plants.

Climate Change—In August 2015, the EPA released a rule, which it called the "Clean Power Plan" (CPP). Under the rule, each state would have to reduce carbon dioxide emissions from its power sector on a state-wide basis by an amount specified by the EPA. The rule was intended to result in a reduction of carbon dioxide emissions from existing power plants across all states to approximately 32% below 2005 levels by 2030.

In February 2016, the United States Supreme Court granted a stay, halting implementation and enforcement of the CPP, pending the resolution of legal challenges to the rule. On March 28, 2017, the President of the United States issued an Executive Order that directed various agencies to review existing regulations that potentially burden the development of the nation's energy resources. The Department of Justice (DOJ) filed requests with the U.S. Court of Appeals for the D.C. Circuit (DC Circuit Court) to suspend and hold in abeyance the current litigation over the CPP in light of the Executive Order while EPA reviews the rule and determines its next steps. The DC Circuit Court granted the requests.

In October 2017, the EPA published in the Federal Register for public comment a proposed CPP repeal rule, in which it outlined the rationale for repealing the CPP. The public comment period for the repeal rule is open until April 26, 2018. Additionally, on December 28, 2017, the EPA published in the Federal Register an Advance Notice of Proposed Rulemaking (ANPR) seeking public comment on specific topics for the EPA to consider in developing any subsequent replacement rule. Public comment on the ANPR is open until February 26, 2018.

The Company cannot predict the impact of the stay, the ultimate outcome of the legal challenges and the regulatory process of the EPA, or whether Oregon will continue to develop an implementation plan in light of recent activities. The Company continues to monitor the developments around the potential new rule.

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.

State of Oregon legislators have proposed Senate Bill 1070 referred to as the Clean Energy Jobs Bill in an effort to reduce greenhouse gas emissions that contribute to climate change through a statewide cap and trade program. This proposal is under consideration in the 35-day legislative session that began in early February. The program would set a statewide cap on greenhouse gas emissions that is reduced over time and would require about 100 companies, including PGE, to acquire permits for the greenhouse gas emissions they produce. PGE continues to monitor the status of this proposed legislation.

Any laws that would impose emissions taxes or mandatory reductions in GHG emissions may have a material impact on PGE's operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. PGE's natural gas-fired facilities, Beaver, Coyote Springs, PW1 and PW2, Carty, and the Company's ownership interest in coal-fired facilities, Boardman and Colstrip, provided, in total, approximately 69% of the Company's net generating capacity at December 31, 2017. If PGE were to incur incremental costs as a result of changes in the regulations regarding GHGs, the Company would seek recovery in customer prices.

Oregon Clean Electricity and Coal Transition Plan—The State of Oregon passed Senate Bill 1547, effective March 8, 2016. The legislation prevents large utilities from including the costs and benefits associated with coal-fired generation in their Oregon retail rates after 2030. For more information regarding the OCEP, and its impact on PGE, see the "*Legal, Regulatory, and Environmental Matters*" section of Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations.

Water Quality

The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification from the state in which the activity will occur. In Oregon, Montana, and Washington, the Departments of Environmental Quality are responsible for reviewing proposed projects under this requirement to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits where required, and has certificates of compliance for its hydroelectric operations under the FERC licenses. The Company is subject to litigation with regard to water quality conditions on the Deschutes River. For additional information on this litigation see "*Deschutes River Alliance Clean Water Act Claims"* in see Note 17, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Threatened and Endangered Species and Wildlife

Fish Protection—The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest that have declined significantly over the last several decades. Long-term recovery plans for these species continue to have operational impacts on many of the region's hydroelectric projects. PGE purchases power in the wholesale market, some of which is sourced from other affected hydroelectric facilities in the Pacific Northwest, to serve its retail load requirements. In addition, the Company 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 FPA. As a result of measures contained in their operating licenses, the Deschutes River and Willamette River projects have been certified as low impact hydro, with a total of 50 MWa of output from those facilities included as part of the Company's renewable energy portfolio used to meet the requirements of the RPS. Conditions required with the operating licenses are expected to result in a minor reduction in power production and continued capital spending to modify the facilities to enhance fish passage and survival.

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

Hazardous Material

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

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

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

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

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

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

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

ITEM 1A. RISK FACTORS.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Access to capital and credit markets is important to PGE's ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. In addition, contractual commitments and regulatory requirements may limit the Company's ability to delay or terminate certain projects.

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

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

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

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

Changes in tax laws may have an adverse impact on the Company's financial position, results of operations, and cash flows.

PGE makes judgments and interpretations about the application of tax law when determining the provision for taxes. Such judgments include the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. Additionally, treatment of tax benefits and costs for ratemaking purposes could be different than what the Company anticipates or requests from the state regulatory commission, which could have a negative effect on the Company's financial condition and results of operations.

PGE owns and operates wind generating facilities, which generate Production Tax Credits (PTCs) that PGE uses to reduce its federal tax obligations. The amount of PTCs earned depends on the level of electricity output generated and the applicable tax credit rate. A variety of operating and economic parameters, including adverse weather conditions and equipment reliability, could significantly reduce the PTCs generated by the Company's wind facilities resulting in a material adverse impact on PGE's financial condition and results of operations. These PTCs generate tax credit carryforwards that the Company plans to utilize in the future to reduce income tax obligations. If PGE cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before the credits expire, the Company may incur material charges to earnings.

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.

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

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

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

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

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

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

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

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

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

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

A portion of PGE's total energy requirement is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. The listing of various plants and species of fish, birds, and other wildlife as threatened or endangered has resulted in significant operational changes to these projects. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission and distribution 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.

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

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

Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2017:

Facility	Location	Net Capacity [1]	
Wholly-owned:			
Natural Gas/Oil:			
Beaver	Clatskanie, Oregon	509	MW
Carty	Boardman, Oregon	437	
Port Westward Unit 1 (PW1)	Clatskanie, Oregon	411	
Coyote Springs	Boardman, Oregon	249	
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		3,857	MW

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

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

Transmission and Distribution

PGE owns and/or has contractual rights associated with transmission lines that deliver electricity from its generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2017, PGE owned an electric transmission system consisting of 1,250 circuit miles as follows: 287 circuit miles of 500 kV line; 402 circuit miles of 230 kV line; and 561 miles of 115 kV line. The Company also has 27,457 circuit miles of distribution lines that deliver electricity to its customers.

The Company also has an ownership interest in, and capacity on, the following:

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

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

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

ITEM 3. LEGAL PROCEEDINGS.

See Note 17, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data," for information regarding legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

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

PGE's common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol "POR". As of February 2, 2018, there were 752 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $41.40 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
2017			
Fourth Quarter	$ 50.11	$ 44.70	$ 0.34
Third Quarter	48.22	44.20	0.34
Second Quarter	48.06	44.04	0.34
First Quarter	46.05	42.41	0.32
2016			
Fourth Quarter	$ 44.32	$ 40.28	$ 0.32
Third Quarter	45.21	41.51	0.32
Second Quarter	44.12	37.77	0.32
First Quarter	40.48	35.27	0.30

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

ITEM 6. SELECTED FINANCIAL DATA.

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

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues, net	$ 2,009	$ 1,923	$ 1,898	$ 1,900	$ 1,810
Income from operations	376	333	309	293	206
Net income	187	193	172	174	104
Net income attributable to Portland General Electric Company	187	193	172	175	105
Earnings per share—basic	2.10	2.17	2.05	2.24	1.36
Earnings per share—diluted	2.10	2.16	2.04	2.18	1.35
Dividends declared per common share	1.340	1.260	1.180	1.115	1.095
Statement of Cash Flows Data:					
Capital expenditures	514	584	598	1,007	656

	As of December 31,				
	2017	2016	2015	2014	2013
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 7,838	$ 7,527	$ 7,210	$ 7,030	$ 6,090
Total long-term debt	2,426	2,350	2,193	2,489	1,905
Total capital lease obligations	51	54	—	—	—
Total Portland General Electric Company shareholders’ equity	2,416	2,344	2,258	1,911	1,819
Common equity ratio	49.4%	49.4%	50.7%	43.4%	48.9%

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

Forward-Looking Statements

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

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

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

- governmental policies and regulatory audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 17, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" of this Annual Report on Form 10-K;
- unseasonable or extreme weather and other natural phenomena, which could affect customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;
- operational factors affecting PGE's power generating facilities, including forced outages, hydro and wind conditions, and disruption of fuel supply, any of which may cause the Company to incur repair costs or purchase replacement power at increased costs;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, either of which could result in the Company's inability to recover project costs;
- volatility in wholesale power and natural gas prices, which could require PGE to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to power and natural gas purchase agreements;
- changes in the availability and price of wholesale power and fuels, including natural gas and coal, and the impact of such changes on the Company's power costs;
- capital market conditions, including availability of capital, volatility of interest rates, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, any of which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, and the repayments of maturing debt;
- future laws, regulations, and proceedings that could increase the Company's costs of operating its thermal generating plants, or affect the operations of such plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- changes in, and compliance with, environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures;

- declines in the fair value of securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities or information technology systems, or result in the release of confidential customer, employee, or Company information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and a significant number of employees approaching retirement;
- new federal, state, and local laws that could have adverse effects on operating results, including the potential impact of the U.S. Tax Cuts and Jobs Act;
- political and economic conditions;
- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

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

Overview

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

PGE is responding proactively to an evolving landscape of customer expectations, technology changes, and regulatory frameworks by focusing efforts on four strategic initiatives: 1) delivering exceptional customer service, 2) investing in a reliable and clean energy future, 3) building a smarter, more resilient grid and 4) pursuing excellence in its work.

Delivering exceptional customer service requires PGE to be responsive to the changing expectations of our growing customer base. PGE's IRP, 2019 GRC, customer information system, and planned infrastructure investments are part of a strategy focused on providing power supply, distribution reliability, and customer service that meet these expectations.

PGE's investments in a reliable and clean energy future are a key element of the IRP, which will require compliance with statutory renewable standards and consideration of state and local government initiatives to decarbonize the local economy.

Building a smarter, more resilient grid is essential to affordably delivering the clean energy future that customers want. This requires embracing new technologies, modernizing the Company's existing infrastructure, and implementing a new customer information system to create a foundation to integrate emerging technologies. PGE's capital requirements contemplate the impact of making these improvements to its transmission, distribution, and information technology infrastructure.

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.

Integrated Resource Plans—PGE's 2016 IRP (2016 IRP) was filed with the OPUC in November 2016 and outlines the Company's plan to meet future customer demand and describes PGE's future energy supply strategy. The 2016 IRP addressed acquisition of additional resources to meet RPS requirements and replace energy and capacity from Boardman, which will cease coal-fired operations at the end of 2020. Further actions identified through 2021 are expected to offset expiring power purchase agreements and integrate variable energy resources, such as wind or solar generation facilities. The 2016 IRP is available on PGE's website. All portfolios analyzed in the 2016 IRP pursued:

- Compliance with the RPS through 2050;
- Inclusion of cost-effective customer-side options, including energy efficiency, demand response, conservation voltage reduction, and dispatchable standby generation; and
- Retention of all existing power plants until 2050, with the exception of Boardman and Colstrip Units 3 & 4.

The 2016 IRP also considered the effects of a law referred to as the Oregon Clean Electricity and Coal Transition Plan (OCEP), which, among other things, increased the RPS requirements for 2025 and future years. For further information on the OCEP, see the *"Legal, Regulatory, and Environmental"* section of the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

In August 2017, the OPUC acknowledged PGE's 2016 IRP and the following primary action plan items:

- Meet additional capacity needs of 561 MW, of which 240 MW must be dispatchable, in 2021;
- Acquire a total of 135 MWa of cost-effective energy efficiency;
- Acquire at least 77 MW (winter) and 69 MW (summer) demand response through 2020 and 16 MW of dispatchable standby generation from customers to help manage peak load conditions and other supply contingencies;
- Deploy 1 MWa of conservation voltage reduction through 2020;
- Submit one or more energy storage proposals in accordance with Oregon House Bill 2193, by January 1, 2018; and
- Perform various research and studies related to flexible capacity and curtailment metrics, customer insights, decarbonization, risks associated with Direct Access, treatment of market capacity, access to resources from Montana, and improvements to load forecasting.

The State of Oregon continues to promote a decarbonized economy that initially began with the decision to cease coal-fired generation at Boardman by the end of 2020. As part of the 2016 IRP, the Company put forth a variety of scenarios in which it envisioned replacement of the output of Boardman. As a result of the public review process, the Company has pursued bilateral contract arrangements with capacity providers in the region. Additional contract requests from Qualifying Facilities have also reduced the need for the Company to build new generation.

Capacity—In August 2017, the Company filed with the OPUC a request for a waiver of the OPUC's competitive bidding guidelines. In that filing, PGE requested a waiver to procure capacity to partially satisfy PGE's capacity needs. The OPUC approved the waiver request in December 2017 and PGE has now finalized bilateral power purchase agreements, summarized as follows:

- 200 MW of annual capacity with five-year terms beginning January 1, 2021; and
- 100 MW of seasonal peak capacity during the summer and winter seasons with a term that would begin July 1, 2019 and continue through February 29, 2024.

Renewables—The OPUC, in its August 2017 acknowledgement, asked the Company to work with OPUC staff and parties to prepare and submit a revised proposal for acquiring renewable resources. In the fourth quarter of 2017, PGE submitted to the OPUC an addendum to the 2016 IRP, which proposed a 100 MWa procurement target for the addition of RPS compliant renewable resources and included a request for the issuance of an RFP for renewable resources. In December 2017, the OPUC acknowledged the addendum and, as a result, the Company plans to move forward with the procurement of additional renewable resources during 2018. The RFP process will include oversight by an independent evaluator and review by the OPUC.

Since issuing the 2016 IRP, PGE has identified a potential benchmark wind resource that could have a nameplate capacity of up to 300 MW that would meet the acknowledged need for renewable resources and qualify for the federal production tax credit. The Company continues to explore this option and should due diligence be completed and agreements reached, the potential benchmark resource would be submitted into the RFP and considered along with other renewable resource proposals.

Energy Storage—Pursuant to OPUC acknowledgment of the 2016 IRP, and in accordance with Oregon House Bill 2193, PGE filed an energy storage proposal in November 2017. The proposal calls for 39 MW of storage to be developed over the next several years at various locations across the grid, at a cost of $50 to $100 million.

IRP Update—The Company plans to file an update to its 2016 IRP in March 2018. As part of the IRP Update filing, PGE's capacity need will have been updated to reflect the bilateral capacity contracts, changes to load forecast, and additional Qualified Facilities executed contracts. The remaining capacity need of approximately 100 MW is expected to be filled through contributions from the acquisition of energy storage, incremental renewables procured through an RFP, contracts with Qualifying Facilities, and market purchases.

General Rate Cases—On February 15, 2018, PGE filed with the OPUC a general rate case based on a 2019 test year (2019 GRC). After adjusting for the effects of tax reform, the Company's filing requests an approximate 4.8% overall increase relative to currently approved prices and would result in an $86 million increase in the annual revenue requirement. The filing seeks recovery of costs related to better serving customers and building a smarter, more resilient system and includes the expectation of higher net variable power costs in 2019.

Primary elements include:

- A new customer information system to provide better, more secure service;
- Replacement and upgrades to equipment to ensure system safety and reliability;
- Equipping substations with technology to address potential outages and shorten those that do occur;
- Strengthening safeguards that protect against cyber attacks and other potential threats; and
- Adding infrastructure to support rapid growth in the region.

The net increase in annual revenue requirement is based upon:

- A capital structure of 50% debt and 50% equity;
- A return on equity of 9.50%
- A cost of capital of 7.31%, and
- A rate base of $4.86 billion.

Regulatory review of the 2019 GRC will continue throughout 2018, with a final order targeted to be issued by the OPUC by December 2018. New customer prices are expected to become effective January 1, 2019.

On January 1, 2018, new customer prices went into effect pursuant to the OPUC order issued on PGE's 2018 GRC, which was based on a 2018 test year and included recovery of costs related to upgrades to PGE's transmission and distribution system, investments in strengthening and safeguarding the grid, and base business costs. The OPUC authorized a $16 million increase in annual revenues, representing an approximate 1% overall increase in customer prices. In addition, the order approved a capital structure of 50% debt and 50% equity, return on equity of 9.50%, cost of capital of 7.35%, and rate base of $4.5 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.

Tax Reform—On December 22, 2017, the Tax Cuts and Jobs Act (the TCJA) was enacted and signed into law by the President of the United States with substantially all of the provisions of the TCJA having an effective date of January 1, 2018. Among other provisions, the reduction of the federal corporate tax rate from 35% to 21%, which required the Company to remeasure its existing deferred income tax balances as of December 31, 2017, had the most impact on PGE's financial condition. As a result of the Company's remeasurement, net deferred tax liabilities on the Company's consolidated balance sheets were reduced by $340 million.

Of the remeasurement amount, $357 million has been deferred as a regulatory liability and is expected to be refunded to customers over time. These deferred tax items relate primarily to Electric utility plant and other rate base items subject to tax normalization rules that require the benefits to be passed on to customers through future prices over the remaining useful life of the underlying assets for which the deferred income taxes relate. The Company plans to use the average rate assumption method to account for the refund to customers. A portion of the remeasurement is not subject to tax normalization rules and will be amortized over time.

The remaining and offsetting remeasurement amount of $17 million represents a reduction to net deferred tax assets related to other business items, primarily comprised of deferred tax assets related to the Company's non-qualified employee benefit plans. The Company has recorded a $17 million charge to the results of operations, reflected as an increase in Income tax expense in the Company's consolidated statements of income for the period ended December 31, 2017.

As a result of the TCJA, PGE expects to incur lower income tax expense in 2018 than what was estimated in setting customer prices in the Company's 2018 GRC. In addition to the effects of the 2017 remeasurement of deferred income taxes, PGE has proposed to defer and refund the 2018 expected net benefits of the TCJA under a deferral application filed with the OPUC on December 29, 2017. If approved as requested, any refund to customers of the net benefits associated with the TCJA in 2018 would be subject to an earnings test and limited by the Company's previously authorized regulated return on equity.

Other specific provisions in the TCJA that relate to regulated public utilities include general allowance for the continued deductibility of interest expense, and continued normalization requirements for accelerated depreciation benefits. These other provisions are not expected to have a material impact on the Company's financial condition, results of operation, or cash flows.

For more information regarding the Company's proposed deferral application, see the "*Legal, Regulatory, and Environmental Matters*" Section of this Item 7.

Capital Requirements and Financing—PGE's capital requirements amounted to $511 million for 2017, with $49 million related to the customer information system, excluding AFDC. The remainder of the 2017 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. In addition, the Company repaid $150 million of debt that was due to mature in November 2017. During 2017, the combination of cash from operations in the amount of $597 million and proceeds from issuances of FMBs in the amount of $225 million funded the Company's capital requirements.

Capital requirements in 2018 are expected to approximate $551 million. PGE plans to fund the 2018 capital requirements with cash from operations during 2018, which is expected to range from $575 million to $625 million and the issuance of debt securities of up to $100 million. For further information, see the "*Liquidity*" and the "*Debt and Equity Financings*" sections of this Item 7.

Operating Activities—PGE, as a vertically-integrated electric utility, engages in the generation, transmission, distribution, and sale of electricity to retail customers within in its approved service territory in the State of Oregon. In addition, the Company purchases and sells electricity in the wholesale market to meet its retail load requirements. In 2017, the Company began participation in the western EIM, which the Company expects will help integrate more renewable energy into the grid by better matching the variable output of renewable resources. PGE also purchases wholesale natural gas in the United States and Canada to fuel its generating portfolio and sells excess gas back into the wholesale market. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to retail customers.

The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues, cash flows, and income from operations to fluctuate from period to period. Historically, PGE has been a winter-peaking utility that typically experiences its highest retail energy demand during the winter heating season. Increased use of air conditioning in the Company's service territory, however, has caused the summer peaks to increase in recent years and the long-term load forecasts indicate summer peaks will exceed winter peaks. PGE's all time summer peak load occurred during August 2017 while the all-time winter peak load was experienced in December 1998. Retail customer price changes and usage patterns, which can be affected by the economy, also have an impact on revenues while wholesale power availability and price, hydro and wind generation, and fuel costs for thermal plants can also affect income from operations.

Customers and Demand—In 2017, retail energy deliveries increased 3.9% from 2016. All retail categories contributed to the increase, which was led by residential deliveries, which are most sensitive to fluctuations in weather. For 2017 and 2016, the average number of retail customers and deliveries, by customer type, were as follows:

	2017		2016		Increase/ (Decrease) in Energy Deliveries
	Average Number of Customers	Energy Deliveries *	Average Number of Customers	Energy Deliveries *	
Residential	762,211	7,880	752,365	7,348	7.2 %
Commercial (PGE sales only)	107,364	6,932	106,460	6,932	— %
Direct Access	491	623	313	525	18.7 %
Total Commercial	107,855	7,555	106,773	7,457	1.3 %
Industrial (PGE sales only)	199	2,943	195	2,968	(0.8)%
Direct Access	68	1,340	63	1,198	11.9 %
Total Industrial	267	4,283	258	4,166	2.8 %
Total (PGE sales only)	869,774	17,755	859,020	17,248	2.9 %
Total Direct Access	559	1,963	376	1,723	13.9 %
Total	870,333	19,718	859,396	18,971	3.9 %

* In thousands of MWh.

In 2017, heating degree-days, an indication of electricity use for heating, were 28% greater than 2016, although only 8% above the 15-year average. Heating degree-days in the first quarter of 2017 were unusually high, in contrast to the unseasonably warm weather that occurred in the first quarter of 2016. While heating degree-days totaled near average for the last three quarters of 2017, they continued to be considerably more than experienced during 2016. Cooling degree-days, a similar indication of the extent to which customers are likely to have used electricity for cooling, were 28% above the 2016 level and 48% above the 15-year normal.

Residential energy deliveries were 7.2% higher in 2017 than 2016 due to the effects of cooler temperatures during the winter season and warmer temperatures during the summer cooling season, as well as customer growth of 1.3%. See *"Revenues"* in the 2017 Compared to 2016 section of Results of Operations within this Item 7, for further information on heating and cooling degree days.

Commercial deliveries also increased by 1.3% as a result of favorable weather conditions and a 1.0 % increase in the average number of customers.

The 2.8% increase in industrial energy deliveries is due to continued increases in energy deliveries to the high-tech manufacturing sector. These increases were partially offset by the closure of a large paper customer in October 2017.

On a weather-adjusted basis, total retail deliveries decreased 0.6% from 2016 reflecting a 2.2% decline in residential deliveries, as residential usage per customer continues a pattern of long-term decline, a 0.7% reduction in commercial deliveries and an additional day in 2016 due to the leap year.

ESSs supplied Direct Access customers with energy representing 10% of the Company's total retail energy deliveries during 2017 and 9% for 2016. The maximum retail load allowed to be supplied under the fixed three-year and minimum five-year opt-out programs represent 13% of the Company's total retail energy deliveries for 2017, and 14% in 2016.

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 through the decoupling mechanism, which is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts. The mechanism provides for collection from (or refund to) customers if weather-adjusted use per customer is less (or more) than the projected baseline set in the Company's most recent approved general rate case. See *"Legal, Regulatory, and Environmental"* in this Overview section of Item 7, for further information on the decoupling mechanism.

For 2017, PGE recorded an estimated collection of $13 million under the mechanism as weather-adjusted energy use per customer was less than that estimated and approved in the Company's 2016 GRC. A final determination of the 2017 estimate will be made by the OPUC through a public filing and review in 2018. Any resulting collection from customers is expected to begin January 1, 2019. The $3 million estimated collection for the 2016 year began January 1, 2018. For 2015, amortization of the net $9 million refund amount occurred in 2017 following a final determination of the amount by the OPUC.

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 90% for the year ended December 31, 2017, and 93% for 2016, and 2015, with the availability of Colstrip, which PGE does not operate, approximating 86%, 85%, and 93%, respectively. During the year ended December 31, 2017, the Company's generating plants provided approximately 69% of its retail load requirement compared to 70% in 2016 and 65% in 2015.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects increased 8% in 2017 compared to 2016, due to more favorable hydro conditions in 2017. These resources provided 18% of the Company's retail load requirement for 2017, compared with 17% for 2016 and 16% for 2015. Energy received from these sources exceeded projected levels included in PGE's AUT by 6% in 2017, did not materially differ from the projections included in the Company's AUT in 2016, and fell short of projections by 7% in 2015. 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 hydroelectric conditions represent the level of energy forecasted to be received from hydroelectric resources for the year and is based on average regional hydro conditions over a recent 30-year period. Any shortfall is generally replaced with power from higher cost sources, while any excess in hydro generation from that projected in the AUT generally displaces power from higher cost sources. See *"Purchased power and fuel"* in the 2017 Compared to 2016 section of Results of Operations in this Item 7, for further detail on regional hydro results.

Energy expected to be received from wind generating resources (Biglow Canyon and Tucannon River) is projected annually in the AUT based on historical generation. Any excess in wind generation from that projected in the AUT generally displaces power from higher-cost sources, while any shortfall is generally replaced with power from higher-cost sources. Energy received from wind generating resources fell short of that projected in PGE's AUT by 18% in 2017, 7% in 2016, and 15% in 2015. Wind generation forecasts are developed using a 5-year rolling average of historical wind levels or forecast studies when historical data is not available. As a result of the generation shortfalls, production tax credits have not materialized to the extent contemplated in the Company's prices.

Pursuant to the Company's PCAM, customer prices can be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in customer prices (baseline NVPC), as established under the AUT, and actual NVPC for the year, to the extent such difference is outside of a pre-determined "deadband," which ranges from $15 million below to $30 million above baseline NVPC. To the extent actual NVPC is above or below the deadband, the PCAM provides for 90% of the variance beyond the deadband to be collected from or refunded to customers, respectively, subject to a regulated earnings test. The following is a summary of the results of the Company's PCAM as calculated for regulatory purposes for 2017, 2016, and 2015:

- For 2017, actual NVPC was above baseline NVPC by $15 million, which was within the established deadband range. Accordingly, no estimated collection from customers was recorded as of December 31, 2017. A final determination regarding the 2017 PCAM results will be made by the OPUC through a public filing and review in 2018.
- For 2016, actual NVPC was below baseline NVPC by $10 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2016. A final determination regarding the 2016 PCAM results was made by the OPUC through a public filing and review in 2017, which confirmed no refund to customers pursuant to the PCAM for 2016.
- For 2015, actual NVPC was below baseline NVPC by $3 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2015. A final determination regarding the 2015 PCAM results was made by the OPUC through a public filing and review in 2016, which confirmed no refund to customers pursuant to the PCAM for 2015.

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

Western EIM—The Company's participation in the western EIM began October 1, 2017. As a market participant in the western EIM, PGE allows certain of its generating plants to receive automated dispatch signals from the CAISO that allows for load balancing with other western EIM participants in five-minute intervals. The Company expects such load balancing will help integrate more renewable energy into the grid by better matching the variable output of renewable resources. Shortly after the entry into the EIM, PGE began to self-integrate its Company-owned wind generation. Additionally, participation in the western EIM gives PGE access to the lowest-cost energy available in the region to meet changes in real-time energy loads and short-term variations in customer demand. For further information on the Company's participation in the western EIM, see *"Federal Regulation"* in the Regulatory section of Item 1.—"Business."

Gas Storage—PGE 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, NW Natural, and may be utilized to provide fuel to PGE's Port Westward Unit 1 and Beaver natural gas-fired generating plants and the Port Westward Unit 2 natural gas-fired flexible capacity generating plant. PGE has entered into a long-term agreement with this gas company to expand the current storage facilities, including the construction of a new reservoir, compressor station, and 13-miles of pipeline, which will collectively be designed to provide no-notice storage services to these PGE generating plants. NW Natural estimates construction will be completed during the winter of 2018-2019, at a cost of approximately $132 million. Due to the level of PGE's involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE has recorded $108 million to construction work-in-progress (CWIP) and a corresponding liability for the same amount to Other noncurrent liabilities in the condensed consolidated balance sheets as of December 31, 2017. Upon completion of the facility, PGE will assess whether the assets and liabilities qualify as a successful sale-leaseback transaction in which the asset and liability are removed and accounted for as either a capital or operating lease.

Carty—Pursuant to the final order issued by the OPUC on November 3, 2015 in connection with the Company's 2016 GRC, the Company was authorized to include in customer prices the capital costs for Carty of up to $514 million, as well as Carty's operating costs, effective August 1, 2016, following the placement of the plant into service on July 29, 2016. As the final construction cost, $637 million, exceeded the amount authorized by the OPUC, higher interest and depreciation expense than allowed in the Company's revenue requirement has resulted. This higher cost of service is primarily due to depreciation and amortization on the incremental capital cost, interest expense, and legal expense, all of which totaled $14 million for the year ended December 31, 2017 and is estimated to be approximately $14 million for the full year 2018.

On July 29, 2016, the Company requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the incremental capital costs for Carty starting from its in service date to the date that such amounts are approved in a subsequent GRC proceeding. The Company has requested the OPUC delay its review of this deferral request until the Company's claims against the Sureties have been resolved. Until such time, the effects of this higher cost of service will be recognized in the Company's results of operations. Any amounts approved by the OPUC for recovery under the deferral filing will be recognized in earnings in the period of such approval.

For additional details regarding various legal and regulatory proceedings related to Carty, see Note 17, Contingencies, in the Notes to the Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

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

- An ongoing environmental investigation of Portland Harbor; and
- The termination of the Construction Agreement for Carty and recovery of related incremental costs.

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

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

Oregon Clean Electricity and Coal Transition Plan—The State of Oregon passed Senate Bill 1547, effective in March 2016, a law referred to as the OCEP. The legislation has impacted PGE in several ways, including preventing the Company from including the costs and benefits associated with coal-fired generation in their Oregon retail rates after 2030 (subject to an exception that extends this date until 2035 for PGE's output from the Colstrip facility). As a result, in October 2016, the Company filed a tariff request, and the OPUC approved the request, to incorporate in customer prices, on January 1, 2017, the approximate $6 million annual effect of accelerating recovery of the Colstrip facility from 2042 to 2030, as required under the legislation.

Future effects under the new law include:

- an increase in RPS thresholds to 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040;
- a limitation on the life of renewable energy certificates (RECs) generated from facilities that become operational after 2022 to five years, but continued unlimited lifespan for all existing RECs and allowance for the generation of additional unlimited RECs for a period of five years for projects on line before December 31, 2022; and
- an allowance for energy storage costs in its renewable adjustment clause mechanism (RAC) filings.

The Company has evaluated the potential impacts and incorporated the effects of the legislation into its 2016 IRP. For further information on the OCEP, see *"State of Oregon Regulation*" in the Regulation section of Item 1.—"Business."

Senate Bill 978—The State of Oregon legislature passed a bill in its 2017 session referred to as SB 978, which directs the OPUC to investigate and provide a report to the legislature by September 15, 2018 on how developing industry trends, technology, and policy drivers in the electricity sector might impact the existing regulatory system and incentives. PGE is actively working on this initiative, both internally and in conjunction with the OPUC, to provide guidance and support development of the report. The OPUC recently opened a proceeding to collect input on possible changes to the regulatory model from stakeholders including regulated utilities such as PGE.

Senate Bill 1070—The State of Oregon legislators have proposed Senate Bill 1070 referred to as the Clean Energy Jobs Bill in an effort to reduce greenhouse gas emissions that contribute to climate change through a statewide cap and trade program. This will be discussed in the 35-day legislative session that began in February. The program would set a statewide cap on greenhouse gas emissions that is reduced over time and would require about 100 companies, including PGE, to acquire permits for the greenhouse gas emissions they produce. PGE continues to monitor the status of this proposed legislation.

Recovery of Utility License Fees—In May 2011, the city of Gresham, Oregon (Gresham), which is within PGE's service territory, adopted a resolution to increase utility license fees from 5% to 7%, effective July 1, 2011. The Company believed that these utility license fees met the definition of privilege taxes within the Oregon statutes and that Gresham's increase violated the statutory 5% limitation on such taxes. PGE began collecting the incremental 2% tax from customers in Gresham, but filed suit against Gresham in Multnomah County Circuit Court, claiming that such an increase in privilege taxes violated Oregon law. In January, 2012, the Multnomah County Circuit Court ruled in favor of PGE, and the Company ceased collecting from Gresham customers the incremental 2% tax. Gresham appealed the Multnomah County Circuit Court decision to the Oregon Court of Appeals, which subsequently ruled in Gresham's favor.

PGE appealed the Court of Appeals' ruling to the Oregon Supreme Court and on August 4, 2016, the Oregon Supreme Court issued its appellate judgment in favor of Gresham. As a result of this ruling, the Company was required to pay Gresham $0.8 million, which represented the amount it had already collected from customers, plus $7 million for the remaining accrued, but uncollected, amount of incremental taxes that were not paid to Gresham when due, covering the period from July 1, 2011 through September 1, 2016. PGE recorded a corresponding regulatory asset for the $7 million.

On February 24, 2017, the Company made a filing requesting that the OPUC allow recovery of the $7 million from customers in Gresham over a five-year period. In November 2017, the OPUC ruled to allow such recovery, which is expected to begin in the first quarter of 2018.

Other Regulatory Matters—The following discussion highlights certain regulatory items that have impacted the Company's revenues, results of operations, or cash flows for 2017 compared with 2016, or have affected retail customer prices, as authorized by the OPUC. In some cases, the Company has deferred the related expenses or benefits as regulatory assets or liabilities, respectively, for later amortization and inclusion in customer prices, pending OPUC review and authorization.

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

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

For further information, see *"Power Operations"* in the Operating Activities section of this Overview, above.

PGE's forecast of power costs for 2016 was approved by the OPUC with an expected reduction in annual revenues of $31 million. This amount was included in the expected net annual revenue requirement increase the OPUC authorized under the Company's 2016 GRC. Actual NVPC for 2016, as calculated for regulatory purposes under the PCAM, was $10 million below the 2016 baseline NVPC.

As a result of the OCEP legislation described above, PGE's 2017 AUT filing included projected PTCs for the 2017 calendar year. Prior to this legislative change, PGE included forecasts of PTCs only in General Rate Case proceedings. The inclusion of PTCs in the AUT provides for annual forecast updates for these estimated tax credits, thus reducing the risk of regulatory lag in terms of adjusting customer prices.

The 2017 AUT filing, approved by the OPUC in November 2016 and included in customer prices effective January 1, 2017, projected a reduction in power costs for 2017, and a corresponding reduction in annual revenue requirement, of $56 million from 2016 levels. Actual NVPC for 2017, as calculated for regulatory purposes under the PCAM, was $15 million above the 2017 baseline NVPC.

As part of its 2018 GRC, PGE included an initial projected reduction in power costs of $29 million that was included in the overall request submitted to the OPUC. As approved by the OPUC in December 2017, the 2018 GRC included a final projected reduction in power costs for 2018 and a corresponding reduction in annual revenue requirement, of $40 million from 2017 levels.

Renewable Resource Costs—Pursuant to the RAC mechanism, PGE can recover in customer prices prudently incurred costs of renewable resources that are expected to be placed in service in the current year. The Company may submit a filing to the OPUC by April 1 each year, with prices expected to become effective January 1 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 1 effective date. No significant filings have been submitted under the RAC during 2017, 2016, or 2015.

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

The Company recorded an estimated collection of $13 million during the year ended December 31, 2017, which resulted from variances between actual weather-adjusted use per customer and that projected in the 2016 GRC. Collections under the decoupling mechanism are subject to an annual limitation, which for 2017 stood at $18 million. Any collection from customers for the 2017 year is expected to occur over a one-year period, which would begin January 1, 2019.

The Company recorded an estimated collection of $3 million during the year ended December 31, 2016, as a result of variances from amounts established in the 2016 GRC. Collection for the year ended December 31, 2016 will occur over a one-year period, which began January 1, 2018.

The $9 million refund recorded in 2015 that resulted from variances between actual weather adjusted use per customer and that projected in the 2015 GRC, occurred during 2017. Similarly, a refund of the $5 million recorded during 2014 occurred during 2016.

Storm Restoration Costs—Beginning in 2011, the OPUC authorized the Company to collect $2 million annually from retail customers to cover incremental expenses related to major storm damages, and to defer any amount not utilized in the current year. The 2018 GRC, as approved by the OPUC, increases the annual collection amount to $3 million, beginning in 2018.

As a result of a series of storm events in the first half of 2017, the Company exhausted the $2 million storm collection authorized for 2017. Consequently, PGE was exposed to the incremental costs related to such major storms events, which totaled $11 million during 2017, less the amount collected in 2017. During 2015 and 2016, PGE fully used the reserve balance as a result of restoration costs associated with storm damage occurring during those years.

As a result of the additional costs incurred, during the first quarter of 2017, PGE filed an application with the OPUC requesting authorization to defer incremental storm restoration costs from the date of the application through the end of 2017. Net of the $2 million being collected annually under the existing methodology, the application seeks deferral of $9 million. The Company is unable to predict how the OPUC will ultimately rule on this application. As a result, no deferral has been recorded as of December 31, 2017.

Portland Harbor Environmental Remediation Account (PHERA) Mechanism—In July 2016, the Company filed an application with the OPUC seeking the deferral of the future environmental remediation costs, as well as seeking authorization to establish a regulatory cost recovery mechanism for such environmental costs. In the first quarter of 2017, the OPUC approved the recovery mechanism, which will allow the Company to defer and recover incurred environmental expenditures through a combination of third-party proceeds, such as insurance recoveries, and through customer prices, as necessary. The mechanism establishes annual prudency reviews of environmental expenditures and is subject to an annual earnings test.

Deferral of 2018 Net Benefits Associated with the U.S. Tax Cuts and Jobs Act—On December 29, 2017, PGE filed with the OPUC an application to defer the 2017 and 2018 financial impacts resulting from the new tax law. If the deferral application is approved as requested, the refund of the net benefits associated with tax reform will be subject to an earnings test and limited by the Company's previously authorized regulated return on equity. For more information regarding the effects of the new tax law on the Company, see the "Tax Reform" of the Overview section of this Item 7.

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.

PGE defines Gross margin as Revenues, net less Purchased power and fuel. Gross margin is considered a non-GAAP measure as it excludes depreciation and amortization and other operation and maintenance expenses. The presentation of Gross margin is intended to supplement an understanding of PGE's operating performance in relation to changes in customer prices, fuel costs, impacts of weather, customer counts and usage patterns, and impact from regulatory mechanisms such as decoupling. The Company's definition of Gross margin may be different from similar terms used by other companies and may not be comparable to their measures.

The results of operations are as follows for the years presented (dollars in millions):

	Years Ended December 31,					
	2017		2016		2015	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net [1]	$ 2,009	100%	$ 1,923	100%	$ 1,898	100%
Purchased power and fuel [1]	592	30	617	32	661	35
Gross margin	1,417	70	1,306	68	1,237	65
Other operating expenses:						
Generation, transmission and distribution	309	16	286	15	266	14
Administrative and other	264	13	247	13	241	13
Depreciation and amortization	345	17	321	16	305	16
Taxes other than income taxes	123	6	119	6	116	6
Total other operating expenses	1,041	52	973	50	928	49
Income from operations	376	18	333	18	309	16
Interest expense, net [2]	120	6	112	6	114	6
Other income:						
Allowance for equity funds used during construction	12	1	21	1	21	1
Miscellaneous income, net	5	—	1	—	1	—
Other income, net	17	1	22	1	22	1
Income before income taxes	273	13	243	13	217	11
Income tax expense	86	4	50	3	45	2
Net income	$ 187	9%	$ 193	10%	$ 172	9%

(1) As reported on PGE's Consolidated Statements of Income

(2) Includes an allowance for borrowed funds used during construction of $6 million in 2017, $11 million in 2016, and $13 million in 2015.

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

	Years Ended December 31,					
	2017		2016		2015	
Revenues[1] (dollars in millions):						
Retail:						
Residential	$ 969	48%	$ 907	47%	$ 895	47%
Commercial	669	33	665	35	662	35
Industrial	212	11	208	11	228	12
Subtotal	1,850	92	1,780	93	1,785	94
Other accrued (deferred) revenues, net	10	1	3	—	(10)	(1)
Total retail revenues	1,860	93	1,783	93	1,775	93
Wholesale revenues	105	5	103	5	88	5
Other operating revenues	44	2	37	2	35	2
Total revenues	$ 2,009	100%	$ 1,923	100%	$ 1,898	100%
Energy deliveries[2] (MWh in thousands):						
Retail:						
Residential	7,880	34%	7,348	33%	7,325	33%
Commercial	7,555	33	7,457	33	7,511	34
Industrial	4,283	19	4,166	19	4,546	21
Total retail energy deliveries	19,718	86	18,971	85	19,382	88
Wholesale energy deliveries	3,193	14	3,352	15	2,560	12
Total energy deliveries	22,911	100%	22,323	100%	21,942	100%
Average number of retail customers:						
Residential	762,211	88%	752,365	88%	742,467	88%
Commercial	107,855	12	106,773	12	105,802	12
Industrial	267	—	258	—	255	—
Total	870,333	100%	859,396	100%	848,524	100%

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those customers that purchase their energy from ESSs. Commercial revenues from ESS customers were $17 million, $13 million, and $12 million for 2017, 2016, and 2015, respectively. Industrial revenues from ESS customers were $20 million, $15 million, and $16 million for 2017, 2016, and 2015, respectively.

(2) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs. Commercial deliveries to ESS customers, in thousands of MWhs, were: 623 in 2017; 525 in 2016; and 509 in 2015. Industrial deliveries to ESS customers, in thousands of MWhs, were: 1,340 in 2017; 1,198 in 2016; and 1,177 in 2015.

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

	Years Ended December 31,					
	2017		2016		2015	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Natural gas	6,228	28%	5,811	27%	4,783	22%
Coal	3,344	15	3,492	16	4,128	19
Total thermal	9,572	43	9,303	43	8,911	41
Hydro	1,774	8	1,629	8	1,453	7
Wind	1,641	8	1,912	9	1,788	8
Total generation	12,987	59	12,844	60	12,152	56
Purchased power:						
Term	7,192	33	6,961	32	7,364	35
Hydro	1,648	7	1,541	7	1,572	7
Wind	264	1	301	1	303	2
Total purchased power	9,104	41	8,803	40	9,239	44
Total system load	22,091	100%	21,647	100%	21,391	100%
Less: wholesale sales	(3,193)		(3,352)		(2,560)	
Retail load requirement	18,898		18,295		18,831	

Net income for the year ended December 31, 2017 was $187 million, or $2.10 per diluted share, compared with $193 million, or $2.16 per diluted share, for the year ended December 31, 2016. The $6 million, or 3%, decrease in net income resulted primarily from the net impact of the following three items: i) Gross margin increased due to higher energy demand, primarily due to weather and strength in the industrial sector; ii) Operating expense increased due to higher depreciation expense as a result of asset base growth, several storms in 2017 that increased restoration expenses, higher administrative and general expenses due to increases in employee count, and additional litigation and interest expense related to Carty; and iii) Income tax expense increased due to higher pre-tax income, the impacts of the TCJA, and lower PTCs.

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

2017 Compared to 2016

Revenues increased $86 million, or 4.5%, in 2017 compared with 2016 as a result of the items discussed below.

Total retail revenues increased $77 million, or 4.3%, in 2017 compared with 2016, primarily due to the net effect of:

- A $71 million increase due to a 3.9% increase in retail energy deliveries consisting of a 7.2% increase in residential deliveries, a 2.8% increase in industrial deliveries, and a 1.3% increase in commercial deliveries. Considerably cooler temperatures in the first half of 2017 than experienced in 2016 combined with warmer temperatures in the summer cooling season in 2017, both drove deliveries higher in 2017 than in 2016. For further information on customer demand, see *"Customers and Demand"* in the Overview section of this Item 7;
- A $10 million increase resulting from the Decoupling mechanism, as an estimated $13 million collection was recorded in 2017; and
- A $5 million increase, directly offset in Depreciation and amortization expense, related to the accelerated cost recovery of Colstrip, partially offset by
- A $5 million reduction as a result of overall price changes, which includes a $55 million reduction in revenues attributable to lower NVPC, as filed in the 2017 AUT; and
- A $3 million decrease due to higher customer credits related to the USDOE settlement in connection with operation of the ISFSI at the former Trojan nuclear power plant site. Such credits are directly offset in Depreciation and amortization expense.

Total heating degree-days in 2017 were above the 15-year average and considerably greater than total heating degree-days in 2016. Total cooling degree-days in 2017 exceeded the 15-year average by 49% and were considerably higher than 2016. The following table presents the number of heating and cooling degree-days in 2017 and 2016, along with the 15-year averages, reflecting that weather had a considerable influence on comparative energy deliveries:

	Heating Degree-Days			Cooling Degree-Days		
	2017	2016	15-Year Average	2017	2016	15-Year Average
1st quarter	2,171	1,585	1,867	—	—	—
2nd quarter	686	403	689	129	154	70
3rd quarter	78	78	78	571	394	399
4th quarter	1,623	1,486	1,599	—	—	2
Total	4,558	3,552	4,233	700	548	471
Increase (decrease) from the 15-year average	8%	(16)%		49%	16%	

On a weather-adjusted basis, total retail energy deliveries in 2017 were 0.6% below 2016 levels. PGE projects that retail energy deliveries for 2018 will be nearly comparable to slightly lower than 2017 weather-adjusted levels, reflecting the closure of a large paper customer in late 2017 as well as continued energy efficiency and conservation efforts.

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

In 2017, the $2 million, or 2%, increase in wholesale revenues from 2016 consisted of a $7 million increase that resulted as a 7% increase in average prices was received when the Company sold power into the wholesale market, partially offset by a $5 million decrease related to 5% less wholesale sales volume.

Other operating revenues increased $7 million, or 19%, in 2017 from 2016, as the sale of excess natural gas not used to fuel the Company's generating facilities accounted for the majority of the increase.

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 2017, Purchased power and fuel expense decreased $25 million, or 4%, from 2016, which was driven by a $38 million, or 6%, decline related to the decrease in the average variable power cost per MWh to $26.80 in 2017 from $28.50 in 2016, partially offset by a $13 million increase resulting from a 2% increase in total system load.

The decrease related to average variable power cost per MWh was driven primarily by: i) a 7% reduction in the average variable power cost per MWh for purchased power as the Company, on average, purchased power at lower market prices; and ii) a 13% reduction in the average variable power cost per MWh related to energy received from the Company's natural gas-fired resources due to lower natural gas prices. This was partially offset by the purchase of replacement power due to 14% less energy received from the Company's wind generating resources.

The net increase in total system load was driven primarily by higher customer demand as a result of the impacts of weather. Energy obtained from the Company's natural gas-fired resources increased 7% due largely to Carty being in service the full year and energy obtained from the Company's hydro resources increased 9% due to more favorable hydro conditions. Energy obtained from purchased power increased 3% in response to higher system load, as well as the purchase of replacement energy due to a reduction in energy received from the Company's wind generating resources.

In 2017, energy received from Biglow Canyon and Tucannon River decreased 14% from 2016 due to less favorable wind conditions, and provided 9% of the Company's retail load requirement in 2017 compared with 10% in 2016. As a result of improved hydro conditions in the region for 2017, energy received from PGE-owned hydroelectric projects in combination with mid-Columbia projects was 8% above 2016 levels, and represented 18% of the Company's retail load requirement for 2017 compared with 17% for 2016.

The following table presents the actual April-to-September 2017 and 2016 runoff at particular points of major rivers relevant to PGE's hydro resources:

	Runoff as a Percent of 30-year Average	
Location	**2017 Actual**	**2016 Actual**
Columbia River at The Dalles, Oregon	98%	89%
Mid-Columbia River at Grand Coulee, Washington	98	91
Clackamas River at Estacada, Oregon	97	71
Deschutes River at Moody, Oregon	98	91

Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, decreased $27 million in 2017 compared with 2016. The decrease attributable to changes in Purchased power and fuel expense was the result of a 6% decline in the average variable power cost per MWh, offset slightly by a 2% increase in total system load. The decrease in actual NVPC was also driven by a 7% increase in the average price per MWh of wholesale power sales, offset slightly by a 5% decrease in the volume of wholesale energy deliveries as a greater portion of its system load was used to meet retail load requirements, largely due to the effects of weather.

For 2017, actual NVPC, as calculated for regulatory purposes under the PCAM, was $15 million above the 2017 baseline NVPC. In 2016, NVPC was $10 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 $23 million, or 8%, in 2017 compared with 2016. The increase was driven by the combination of $10 million in higher costs due to the addition of Carty, $8 million higher service restoration and storm costs, $3 million higher plant maintenance expenses, and $2 million higher information technology expenses.

Administrative and other expense increased $17 million, or 7%, in 2017 compared with 2016, primarily due to $12 million higher overall labor and employee benefit expenses and $3 million higher legal costs attributable to Carty.

Depreciation and amortization expense in 2017 increased $24 million, or 7%, compared with 2016. The increase was primarily driven by $26 million higher expense resulting from capital additions, offset by a $3 million reduction in expense due to higher amortization credits in 2017 of the regulatory liability for the ISFSI spent fuel settlement. The overall impact resulting from the amortization of the regulatory assets and liabilities is directly offset by corresponding reductions in retail revenues.

Taxes other than income taxes expense increased $4 million, or 3%, in 2017 compared with 2016, driven by $2 million higher Oregon property taxes and $2 million higher payroll taxes.

Interest expense increased $8 million, or 7%, in 2017 compared with 2016 due to a $4 million decrease in the credits for the allowance for borrowed funds used during construction (primarily due to the Carty plant being placed in service in 2016) and increased expense of $3 million resulting from a 5% increase in the average balance of debt outstanding.

Other income, net was $17 million in 2017 compared to $22 million in 2016, with the decrease primarily due to lower allowance for equity funds used during construction, which resulted from Carty being placed in service during 2016.

Income tax expense increased $36 million, or 72%, in 2017 compared to 2016. The change relates to a $13 million increase due to higher pre-tax income and $7 million due to lower production tax credits. Additionally, Income tax expense increased $17 million due to the remeasurement of deferred taxes pursuant to the change in corporate tax rates in the TCJA. For more information regarding the Company's proposed deferral application, see the "*Legal, Regulatory, and Environmental Matters*" Section of this Item 7.

2016 Compared to 2015

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

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

- A $49 million increase resulting from price changes, as authorized by the OPUC, including Carty going into service and into customer prices in mid-2016, as a result of the Company's 2016 GRC;
- A $10 million increase resulting from the Decoupling mechanism, as an estimated $3 million collection was recorded in 2016 compared to a refund in 2015;
- A $5 million increase due to a lower amount of customer credits related to tax credits in connection with operation of the ISFSI at the former Trojan nuclear power plant site. Such credits are directly offset in depreciation and amortization expense; and
- A $5 million overall increase due to various other largely offsetting tariff changes and adjustments; partially offset by
- A $38 million decrease in revenues related to a 2.1% decrease in retail energy deliveries, consisting of 8.4% and 0.7% decreases in industrial and commercial deliveries, respectively, partially offset by a 0.3% increase in residential deliveries. See *"Customers and Demand"* in the Overview section of this Item 7. for further information on customer demand; and

- A $23 million decrease related to the collection from customers during 2015 of costs associated with previous capital project deferrals, with no comparable collection in 2016. This decrease in revenues is largely offset by a comparable decrease in depreciation and amortization expense.

Total heating degree-days in 2016 were lower than the 15-year average although somewhat greater than total heating degree-days in 2015. Total cooling degree-days in 2016 exceeded the 15-year average although were considerably less than the 2015 total. The following table presents the number of heating and cooling degree-days in 2016 and 2015, along with the 15-year averages:

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

On a weather-adjusted basis, retail energy deliveries in 2016 were 1.4% below 2015 although one large paper customer ceased operations in late 2015. On a comparable year over year basis, with the removal of the one large paper customer load from the 2015 year, the Company experienced weather-adjusted load growth of 0.9%.

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

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

Purchased power and fuel expense in 2016 decreased $44 million, or 7%, from 2015, driven by a $51 million, or 8%, decline related to the decrease in the average variable power cost per MWh to $28.50 in 2016 from $30.91 in 2015, partially offset by a $7 million increase resulting from a 1% increase in total system load.

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

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

The following table presents the actual of the April-to-September runoff for 2016 and 2015:

Location	Runoff as a Percent of 30-year Average	
	2016 Actual	2015 Actual
Columbia River at The Dalles, Oregon	89%	69%
Mid-Columbia River at Grand Coulee, Washington	91	77
Clackamas River at Estacada, Oregon	71	53
Deschutes River at Moody, Oregon	91	85

Actual NVPC decreased $59 million for 2016 compared with 2015. The decrease attributable to changes in Purchased power and fuel expense was the result of an 8% decline in the average variable power cost per MWh, offset slightly by a 1% increase in total system load. The decrease in actual NVPC was also driven by a 31% increase in the volume of wholesale energy deliveries as the Company's retail load requirement decreased in 2016, largely due to the effects of weather, which resulted in a greater portion of its system load being sold into the wholesale market. The increase was partially offset by an 11% decrease in the average price per MWh of wholesale power sales. The 2016 GRC had anticipated a decrease of approximately $31 million in NVPC from the 2015 baseline, with customer prices set accordingly. For 2016, actual NVPC, as calculated for regulatory purposes under the PCAM, was $10 million below the 2016 baseline NVPC, compared with $3 million below for 2015.

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

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

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

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

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

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

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

Liquidity and Capital Resources

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

Capital Requirements

The following table presents actual capital expenditures and debt maturities for 2017 and projected capital expenditures and future debt maturities for 2018 through 2022 (in millions, excluding AFDC):

	Years Ending December 31,					
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
Ongoing capital expenditures[1]	$ 462	$ 535	$ 444	$ 451	$ 440	$ 450
Customer information system[2]	49	16	—	—	—	—
Total capital expenditures	$ 511 [3]	$ 551	$ 444	$ 451	$ 440	$ 450
Long-term debt maturities	$ 150	$ —	$ 300	$ —	$ 160	$ —

(1) Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connects.
(2) Total capital expenditures for the customer information system through December 31, 2017 were $114 million, excluding AFDC.
(3) Includes 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.

Liquidity

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

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

	Years Ended December 31,		
	2017	2016	2015
Cash and cash equivalents, beginning of year	$ 6	$ 4	$ 127
Net cash provided by (used in):			
Operating activities	597	553	520
Investing activities	(514)	(585)	(522)
Financing activities	(50)	34	(121)
Net change in cash and cash equivalents	33	2	(123)
Cash and cash equivalents, end of year	$ 39	$ 6	$ 4

2017 Compared to 2016

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 $44 million increase in cash flows from operating activities in 2017 compared to 2016 reflects that while Net income was nearly comparable, adjustments to Net income to reconcile to net cash provided included increases of $33 million for Deferred income taxes ($17 million of which related to Tax reform), $22 million for Other non-cash income and expenses, and $24 million for Depreciation and amortization expense. Somewhat offsetting those increases were decreases of $28 million from Margin deposits outstanding due to changes in prices of power and fuel underlying contracts with counterparties and $16 million as a result of the Decoupling mechanism, which reflects both the current year deferral and the refund to customers related to prior years.

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 2018 will range from $370 million to $380 million. Combined with all other sources, cash provided by operations in 2018 is estimated to range from $575 million to $625 million.

As a result of the tax law changes made under the TCJA, PGE's operating cash flows are generally expected to decrease in the future as customer prices will reflect lower income tax expense recoveries going forward, as well as refunds of the net benefits of changes in tax law under the TCJA, offset partially by the impacts of higher rate base over time. PGE expects that customer prices will be adjusted for the impacts of the TCJA as a part of the Company's 2019 GRC. Currently, the Company does not believe this decrease in future operating cash flows will have a material impact on its future liquidity or credit ratings. For more information regarding the effects of the new tax law on the Company, see the "Tax Reform" of the Overview section of this Item 7.

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 $71 million decrease in net cash used in investing activities in 2017 compared to 2016 was primarily due to a decrease in Capital expenditures as Carty was placed into service in July 2016.

The Company plans for approximately $551 million of capital expenditures in 2018 related to upgrades to and replacement of generation, transmission, and distribution infrastructure. PGE plans to fund the 2018 capital expenditures with cash from operations during 2018, as discussed above, as well as with the issuance of short- and long-term debt securities. For additional information, see "*Capital Requirements*" and "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2017, cash used in financing activities consisted primarily of the issuance of $225 million of long-term debt, less the repayment $150 million of term loans and payment of dividends in the amount of $118 million. During 2016, cash provided by financing activities consisted of the issuance of $290 million of long-term debt less the repayment of $133 million of FMBs and the payment of dividends of $110 million.

2016 Compared to 2015

Cash Flows from Operating Activities—The $33 million increase in cash flows from operating activities in 2016 compared to 2015 was largely due to increases in net income and depreciation expense, partly offset by the impact of changes in other non-cash income and expense items including amounts recorded under the decoupling mechanism, and a decrease in margin deposits. The remaining non-cash income and expenses and other components of working capital were fairly consistent year over year.

Cash Flows from Investing Activities—The $63 million increase in net cash used in investing activities in 2016 compared to 2015 was primarily due to a distribution of $50 million from the Nuclear decommissioning trust and $23 million the Company received from a sales tax refund related to Tucannon River, both in 2015. Capital expenditures decreased $14 million as Carty was placed into service in July 2016. For additional information regarding the distribution from the Nuclear decommissioning trust, see Note 3, Balance Sheet Components, and Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Cash Flows from Financing Activities—During 2016, cash provided by financing activities consisted of the issuance of $290 million of long-term debt less the repayment $133 million of FMBs and dividends of $110 million. During 2015, cash used in financing activities consisted of repayments of long-term debt of $442 million and the payment of dividends of $97 million.

Dividends on Common Stock

The following table presents common stock dividends declared in 2017:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 15, 2017	March 27, 2017	April 17, 2017	$ 0.32
April 26, 2017	June 26, 2017	July 17, 2017	0.34
July 26, 2017	September 25, 2017	October 16, 2017	0.34
October 25, 2017	December 26, 2017	January 16, 2018	0.34

While the Company expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. On February 14, 2018, a common stock dividend of $0.34 per share was declared, payable April 16, 2018 to shareholders of record on March 26, 2018. 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	P-2	A-2
Outlook	Stable	Positive

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, 2017, PGE had posted $42 million of collateral with these counterparties, consisting of $11 million in cash and $31 million in bank letters of credit, $11 million of which is related to master netting agreements. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2017, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is $84 million and decreases to $14 million by December 31, 2018 and $5 million by December 31, 2019. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is $175 million and decreases to $88 million by December 31, 2018 and $64 million by December 31, 2019.

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

The Indenture securing PGE's outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. Interest is payable semi-annually on FMBs. The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2017, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to $1.1 billion of additional FMBs. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges, or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65% of total capitalization (debt to total capital ratio). As of December 31, 2017, the Company's debt to total capital ratio, as calculated under the credit agreements, was 51.8%.

Debt and Equity Financings

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

For 2018, PGE expects to fund estimated capital requirements with cash from operations, the issuance of debt securities of up to $100 million, and the issuance of commercial paper, as needed. The actual timing and amount of any such issuances of debt or commercial paper will be dependent upon the timing and amount of capital expenditures.

Short-term Debt—PGE has approval from the FERC to issue short-term debt up to a total of $900 million through February 6, 2020.

As of December 31, 2017, PGE had a $500 million revolving credit facility scheduled to expire in November 2021. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and for general corporate purposes. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility.

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

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

Under the revolving credit facility, as of December 31, 2017, PGE had no borrowings outstanding, and no commercial paper or letters of credit issued. As a result, as of December 31, 2017, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities under which the Company can request letters of credit for original terms not to exceed one year. These facilities provide for a total capacity of $220 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 $67 million were outstanding as of December 31, 2017.

Long-term Debt—During 2017, PGE issued a total of $225 million of FMBs at an interest rate of 3.98%. PGE drew $75 million in August 2017 with a maturity date of 2048 and drew the remaining $150 million in November 2017 with a maturity of 2047.

In 2017, PGE repaid three separate term loans drawn on an unsecured credit agreement under which it had borrowed $150 million from certain financial institutions. PGE repaid the loan as follows:

- $50 million on August 21, 2017;
- $25 million on October 30, 2017; and
- $75 million on November 27, 2017.

As of December 31, 2017, total long-term debt outstanding, net of $10 million unamortized debt expense, was $2,426 million, of which none is scheduled to mature in 2018.

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 ratio was 49.4% as of December 31, 2017 and 2016.

Contractual Obligations and Commercial Commitments

The following table presents PGE's contractual obligations as of December 31, 2017 (in millions):

	2018	2019	2020	2021	2022	There-after	Total
Long-term debt	$ —	$ 300	$ —	$ 160	$ —	$ 1,976	$ 2,436
Interest on long-term debt (1)	123	110	104	100	99	1,574	2,110
Capital and other purchase commitments	191	2	10	2	2	58	265
Purchased power and fuel:							
Electricity purchases	156	156	201	200	187	1,733	2,633
Capacity contracts	6	5	4	4	4	8	31
Public Utility Districts	9	17	16	16	15	85	158
Natural gas	51	35	28	25	24	140	303
Coal and transportation	15	5	—	—	—	—	20
Pension Plan Contributions (2)	21	17	17	18	24	—	97
Capital leases	7	6	6	6	5	72	102
Build-to-suit lease	—	15	15	14	14	260	318
Operating leases	9	8	6	6	8	165	202
Total	$ 588	$ 676	$ 407	$ 551	$ 382	$ 6,071	$ 8,675

(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, 2017.

(2) Contributions beyond 2022 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 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 through August 2018, after which PGE would be responsible for a pro-rata portion of the defaulting purchaser's share with no limitation, regardless of the reason for any default. For the Priest Rapids and Wanapum projects, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any of the public utility district's outstanding debt for the portion of the project that benefits tax exempt purchasers. For additional information on these long-term power purchase agreements, see "*Public utility districts*" in Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Off-Balance Sheet Arrangements

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

Critical Accounting Policies

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

Regulatory Accounting

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

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

Asset Retirement Obligations

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

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

Revenue Recognition

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

Contingencies

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

Pension Plan

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

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

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or reduction in the discount rate, would have the effect of increasing the 2017 net periodic pension expense by approximately $2 million.

Fair Value Measurements

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

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

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

Risk Management Committee

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

Commodity Price Risk

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

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2017 that are expected to settle in each respective year (in millions):

	2018	2019	2020	2021	2022	Thereafter	Total
Commodity contracts:							
Electricity	$ 10	$ 8	$ 8	$ 8	$ 7	$ 91	$ 132
Natural gas	43	20	7	2	—	—	72
	$ 53	$ 28	$ 15	$ 10	$ 7	$ 91	$ 204

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

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

Foreign Currency Exchange Rate Risk

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

As of December 31, 2017, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

Interest Rate Risk

To meet short-term cash requirements, PGE has the ability to issue commercial paper for terms of up to 270 days and has a revolving credit facility that permits same day borrowings. Although any borrowings under the commercial paper program or the revolving credit facility carry a fixed rate during their respective terms, the short-term nature of such borrowings subjects the Company to fluctuations in interest rates that result from changes in market conditions. As of December 31, 2017, PGE had no borrowings outstanding under its revolving credit facility and no commercial paper or other short-term debt outstanding.

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

As of December 31, 2017, the total fair value and carrying amounts by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date					
		Total	2018	2019	2020	2021	There-after
First Mortgage Bonds	$ 2,698	$ 2,315	$ —	$ 300	$ —	$ 160	$ 1,855
Pollution Control Revenue Bonds	131	121	—	—	—	—	121
Total	$ 2,829	$ 2,436	$ —	$ 300	$ —	$ 160	$ 1,976

As of December 31, 2017, PGE had no long-term debt instruments subject to interest rate risk exposures.

Credit Risk

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

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

As of December 31, 2017, PGE's credit risk exposure is $9 million for commodity activities with externally-rated investment grade counterparties. The underlying transactions that make up the exposure will mature during 2019. The exposure is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

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

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Portland General Electric Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 15, 2018

We have served as the Company's auditor since 2004.

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

	Years Ended December 31,		
	2017	2016	2015
Revenues, net	$ 2,009	$ 1,923	$ 1,898
Operating expenses:			
Purchased power and fuel	592	617	661
Generation, transmission and distribution	309	286	266
Administrative and other	264	247	241
Depreciation and amortization	345	321	305
Taxes other than income taxes	123	119	116
Total operating expenses	1,633	1,590	1,589
Income from operations	376	333	309
Interest expense, net	120	112	114
Other income:			
Allowance for equity funds used during construction	12	21	21
Miscellaneous income, net	5	1	1
Other income, net	17	22	22
Income before income taxes	273	243	217
Income tax expense	86	50	45
Net income	$ 187	$ 193	$ 172
Weighted-average shares outstanding (in thousands):			
Basic	89,056	88,896	84,180
Diluted	89,176	89,054	84,341
Earnings per share:			
Basic	$ 2.10	$ 2.17	$ 2.05
Diluted	$ 2.10	$ 2.16	$ 2.04

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2017	2016	2015
Net income	$ 187	$ 193	$ 172
Other comprehensive (loss) income—Change in compensation retirement benefits liability and amortization, net of taxes of an immaterial amount in 2017, 2016, and 2015	(1)	1	(1)
Comprehensive income	$ 186	$ 194	$ 171

See accompanying notes to consolidated financial statements.

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

	As of December 31,	
	2017	2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 39	$ 6
Accounts receivable, net	168	155
Unbilled revenues	106	107
Inventories, at average cost:		
Materials and supplies	52	50
Fuel	26	32
Regulatory assets—current	62	36
Other current assets	73	77
Total current assets	526	463
Electric utility plant:		
Generation	4,667	4,597
Transmission	547	521
Distribution	3,543	3,343
General	550	501
Intangible	607	572
Construction work-in-progress	391	213
Total electric utility plant	10,305	9,747
Accumulated depreciation and amortization	(3,564)	(3,313)
Electric utility plant, net	6,741	6,434
Regulatory assets—noncurrent	438	498
Nuclear decommissioning trust	42	41
Non-qualified benefit plan trust	37	34
Other noncurrent assets	54	57
Total assets	$ 7,838	$ 7,527

See accompanying notes to consolidated financial statements.

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

	As of December 31,	
	2017	**2016**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 132	$ 129
Liabilities from price risk management activities—current	59	44
Current portion of long-term debt	—	150
Accrued expenses and other current liabilities	241	254
Total current liabilities	432	577
Long-term debt, net of current portion	2,426	2,200
Regulatory liabilities—noncurrent	1,288	958
Deferred income taxes	376	669
Unfunded status of pension and postretirement plans	284	281
Liabilities from price risk management activities—noncurrent	151	125
Asset retirement obligations	167	161
Non-qualified benefit plan liabilities	106	105
Other noncurrent liabilities	192	107
Total liabilities	5,422	5,183
Commitments and contingencies (see notes)		
Equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding	—	—
Common stock, no par value, 160,000,000 shares authorized; 89,114,265 and 88,946,704 shares issued and outstanding as of December 31, 2017 and 2016, respectively	1,207	1,201
Accumulated other comprehensive loss	(8)	(7)
Retained earnings	1,217	1,150
Total equity	2,416	2,344
Total liabilities and equity	$ 7,838	$ 7,527

See accompanying notes to consolidated financial statements.

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

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Shares	Amount			
Balance as of December 31, 2014	78,228,339	$ 918	$ (7)	$ 1,000	$ 1,911
Issuances of common stock, net of issuance costs of $12	10,400,000	271	—	—	271
Shares issued pursuant to equity-based plans	164,412	1	—	—	1
Stock-based compensation	—	6	—	—	6
Dividends declared ($1.18 per share)	—	—	—	(102)	(102)
Net income	—	—	—	172	172
Other comprehensive (loss)	—	—	(1)	—	(1)
Balance as of December 31, 2015	88,792,751	1,196	(8)	1,070	2,258
Shares issued pursuant to equity-based plans	153,953	1	—	—	1
Stock-based compensation	—	4	—	—	4
Dividends declared ($1.26 per share)	—	—	—	(113)	(113)
Net income	—	—	—	193	193
Other comprehensive income	—	—	1	—	1
Balance as of December 31, 2016	88,946,704	1,201	(7)	1,150	2,344
Shares issued pursuant to equity-based plans	167,561	2	—	—	2
Stock-based compensation	—	4	—	—	4
Dividends declared ($1.34 per share)	—	—	—	(120)	(120)
Net income	—	—	—	187	187
Other comprehensive (loss)	—	—	(1)	—	(1)
Balance as of December 31, 2017	89,114,265	$ 1,207	$ (8)	$ 1,217	$ 2,416

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2017	**2016**	**2015**
Cash flows from operating activities:			
Net income	$ 187	$ 193	$ 172
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	345	321	305
Deferred income taxes	70	37	40
Allowance for equity funds used during construction	(12)	(21)	(21)
Pension and other postretirement benefits	24	28	34
Unrealized losses on non-qualified benefit plan trust assets	2	5	6
Decoupling mechanism deferrals, net of amortization	(22)	(6)	14
Other non-cash income and expenses, net	29	7	22
Changes in working capital:			
(Increase) in receivables and unbilled revenues	(3)	(9)	(11)
(Increase) decrease in margin deposits	(3)	25	(22)
Increase in payables and accrued liabilities	5	15	6
Other working capital items, net	1	(4)	(4)
Contribution to non-qualified employee benefit trust	(8)	(10)	(9)
Other, net	(18)	(28)	(12)
Net cash provided by operating activities	597	553	520
Cash flows from investing activities:			
Capital expenditures	(514)	(584)	(598)
Purchases of nuclear decommissioning trust securities	(18)	(25)	(19)
Sales of nuclear decommissioning trust securities	21	27	22
Distribution from nuclear decommissioning trust	—	—	50
Sales tax refund received - Tucannon River Wind Farm	—	—	23
Other, net	(3)	(3)	—
Net cash used in investing activities	(514)	(585)	(522)

See accompanying notes to consolidated financial statements.

Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 225	$ 290	$ 145
Payments on long-term debt	(150)	(133)	(442)
Proceeds from issuances of common stock, net of issuance costs	—	—	271
(Maturities) issuances of commercial paper, net	—	(6)	6
Dividends paid	(118)	(110)	(97)
Other	(7)	(7)	(4)
Net cash (used in) provided by financing activities	(50)	34	(121)
Increase (decrease) in cash and cash equivalents	33	2	(123)
Cash and cash equivalents, beginning of year	6	4	127
Cash and cash equivalents, end of year	$ 39	$ 6	$ 4

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

	Years Ended December 31,		
	2017	2016	2015
Supplemental disclosures of cash flow information:			
Cash paid for:			
Interest, net of amounts capitalized	$ 110	$ 104	$ 108
Income taxes	18	16	3
Non-cash investing and financing activities:			
Accrued capital additions	53	50	32
Accrued dividends payable	31	30	28
Assets obtained under leasing arrangements	87	78	—

See accompanying notes to consolidated financial statements.

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) is a single, vertically-integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company's corporate headquarters is located in Portland, Oregon and its approximately 4,000 square mile, state-approved service area is located entirely within the State of Oregon. PGE's allocated service area includes 51 incorporated cities, of which Portland and Salem are the largest. As of December 31, 2017, PGE served approximately 875,000 retail customers with a service area population of approximately 1.9 million, comprising approximately 46% of the population of the state.

As of December 31, 2017, PGE had 2,906 employees, with 785 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 732 and 53 employees and expire March 2020 and August 2022, respectively.

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

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in its consolidated financial statements. For further information on PGE's jointly-owned plant, see Note 16, Jointly-Owned Plant. Intercompany balances and transactions have been eliminated.

For entities that are determined to meet the definition of a VIE and in which the Company has determined it is the primary beneficiary, the VIE is consolidated and a noncontrolling interest is recognized for any third party interests. This has resulted in the Company consolidating entities in which it has less than a 50% equity interest. There were no material VIEs in 2017 or 2016.

Use of Estimates

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

Reclassifications

To conform with the 2017 presentation, PGE has reclassified Cash received to be returned to customers pursuant to the Residential Exchange Program, net of amortization of $6 million and $1 million in 2016 and 2015, respectively, and Contribution to voluntary employees' benefit association trust of $2 million and $4 million in 2016 and 2015, respectively, to Other net within the operating activities section of the Consolidated Statements of Cash Flows. PGE has also reclassified the Regulatory deferral of settled derivative instruments of $2 million in both 2016 and 2015 to Other non-cash income and expense, net within the operating activities section of the Consolidated Statements of Cash Flows.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents, of which PGE had $30 million as of December 31, 2017 and $1 million as of December 31, 2016 included within Cash and cash equivalents in the consolidated balance sheets.

Accounts Receivable

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

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

Provisions for uncollectible accounts receivable related to wholesale sales are charged to Purchased power and fuel expense and are recorded periodically based on a review of counterparty non-performance risk and contractual right of offset when applicable. There have been no material write-offs of accounts receivable related to wholesale sales in 2017, 2016, or 2015.

Price Risk Management

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

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

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

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

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral with certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are included within Other current assets in the consolidated balance sheets and were $11 million and $8 million as of December 31, 2017 and 2016, respectively. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheet and were $31 million and $17 million as of December 31, 2017 and 2016, respectively.

Inventories

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

Electric Utility Plant

Capitalization Policy

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

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

PGE records AFDC, which is intended to represent the Company's cost of funds used for construction purposes, based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. AFDC is capitalized as part of the cost of plant and credited to the consolidated statements of income. The average rate used by PGE was 7.3% in 2017, 2016, and 2015. AFDC from borrowed funds was $6 million in 2017, $11 million in 2016, and $13 million in 2015 and is reflected as a reduction to Interest expense. AFDC from equity funds, included in Other income, net, was $12 million in 2017, and $21 million in 2016 and 2015.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was 3.6% in 2017, 3.5% in 2016 and 3.6% in 2015. A component of depreciation expense includes estimated asset retirement removal costs allowed in customer prices.

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

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

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

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

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $296 million and $257 million as of December 31, 2017 and 2016, respectively, with amortization expense of $46 million in 2017, and $44 million in 2016 and $38 million in 2015. Future estimated amortization expense as of December 31, 2017 is as follows: $49 million in 2018; $48 million in 2019; $43 million in 2020; $35 million in 2021; and $28 million in 2022.

Marketable Securities

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

Regulatory Accounting

Regulatory Assets and Liabilities

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

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

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

Power Cost Adjustment Mechanism

PGE is subject to a power cost adjustment mechanism (PCAM) as approved by the OPUC. Pursuant to the PCAM, the Company can adjust future customer prices to reflect a portion of the difference between net variable power costs (NVPC) forecast each year and included in customer prices (baseline NVPC) and actual NVPC. NVPC consists of the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts, all of which is classified as Purchased power and fuel in the Company's consolidated statements of income, and is net of wholesale sales, which are classified as Revenues, net in the consolidated statements of income.

The Company is subject to a portion of the business risk or benefit associated with the difference between actual and baseline NVPC by application of an asymmetrical deadband, which ranges from $15 million below to $30 million above baseline NVPC.

To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from or refunded to customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for the given year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 9.6% for 2017, 9.6% for 2016, and 9.68% for 2015.

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

Asset Retirement Obligations

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

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

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

The difference between the timing of the recognition of ARO depreciation and accretion expenses and the amount included in customers' prices is recorded as a regulatory asset or liability in the Company's consolidated balance sheets. PGE had a regulatory liability related to AROs in the amount of $52 million as of December 31, 2017 and $49 million as of December 31, 2016. For additional information concerning the Company's regulatory liability related to AROs, see Note 6, Regulatory Assets and Liabilities.

Contingencies

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

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

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

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

Accumulated Other Comprehensive Loss

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

Revenue Recognition

Revenues are recognized as electricity is delivered to customers and include amounts for any services provided. Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $43 million in 2017, 2016 and 2015.

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

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

Stock-Based Compensation

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

Income Taxes

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

Because PGE is a rate-regulated enterprise, changes in certain deferred tax assets and liabilities are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. Such amounts were recognized as net regulatory liabilities of $277 million and net regulatory assets of $86 million as of December 31, 2017, and 2016, respectively, and will be included in prices when the temporary differences reverse.

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

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

Recent Accounting Pronouncements

Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers* (Topic 606) (ASU 2014-09), creates a new Topic 606 and supersedes the revenue recognition requirements in Topic 605, *Revenue*

Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. ASU 2014-09 provides a five-step analysis of transactions to determine when and how revenue is recognized that consists of: i) identify the contract with the customer; ii) identify the performance obligations in the contract; iii) determine the transaction price; iv) allocate the transaction price to the performance obligations; and v) recognize revenue when or as each performance obligation is satisfied. Companies can transition to the requirements of this ASU either retrospectively (full retrospective method) or as a cumulative-effect adjustment as of the effective date (modified retrospective method), which is January 1, 2018 for calendar year-end public entities. The Company plans to elect the modified retrospective method for implementation. PGE does not anticipate any material changes to its revenue recognition policy for tariff-based revenues, which comprises a majority of PGE's retail, wholesale, and other revenues, as performance obligations are expected to be satisfied in a similar recognition pattern. PGE continues to finalize its evaluation of certain matters of presentation such as alternative revenue programs (including decoupling) and enhanced required disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* which supersedes the current lease accounting requirements for lessees and lessors within Topic 840, *Leases*. Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases, on the balance sheet and record corresponding right-of-use assets and lease liabilities. Accounting for lessors is substantially unchanged from current accounting principles. Lessees will be required to classify leases as either finance leases or operating leases. Initial balance sheet measurement is similar for both types of leases; however, expense recognition and amortization of right-of-use assets will differ. Operating leases will reflect lease expense on a straight-line basis, while finance leases will result in the separate presentation of interest expense on the lease liability (as calculated using the effective interest method) and amortization expense of the right-of-use asset. Quantitative and qualitative disclosures will also be required surrounding significant judgments made by management. The provisions of this pronouncement are effective for calendar year-end, public entities on January 1, 2019. As issued, ASU 2016-02 requires transition under a modified retrospective basis as of the beginning of the earliest comparative period presented, however the Company is monitoring the FASB's decisions regarding potential transition practical expedients that would allow companies to adopt the new standard with a cumulative effect adjustment as of the beginning of the year of adoption with prior year comparative financial information and disclosures remaining as previously reported. Early adoption is permitted, but the Company does not plan to early adopt. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842) Land Easement Practical Expedient for Transition to Topic 842*, which amends ASU 2016-02 to provide entities an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 842. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. PGE plans to elect this practical expedient. The Company is monitoring utility industry implementation issues that may change existing and future lease classification in areas such as purchase power agreements, pipeline laterals, utility pole attachments, and other utility industry-related arrangements. In conjunction with monitoring industry issues that may impact lease classification, the Company is in the process of evaluating whether it will elect to adopt certain other, optional practical expedients included within the standard. Decisions surrounding the election of practical expedients may impact the Company's lease population that is ultimately recorded. As a result, PGE has not yet quantified the estimated financial statement impact, but overall, the Company does expect an increase in the recognition of right-of-use assets and lease liabilities on the Company's consolidated balance sheet.

In March 2017, the FASB issued ASU 2017-07, *Compensation-Retirement Benefits (Topic 715), Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). Pursuant to this ASU, only the service cost component of net periodic pension and postretirement benefit costs will be eligible for capitalization and should be applied on a prospective basis upon implementation. Also, the non-service components are required to be presented in the income statement separately from the service cost component and outside the subtotal of income from operations and should be applied on a retrospective basis upon implementation. For calendar year-end public entities, the update will be effective for annual periods beginning January 1, 2018. The Company does not plan to early adopt. For ratemaking purposes, the Company will continue to be allowed to recover this portion of the non-service costs as a component of rate base, however such amounts will be recorded as Regulatory assets on the Company's condensed consolidated balance sheets, instead of Utility plant, and amortized in a systematic and rational manner and reflected as expense in a line item outside the subtotal of income from operations on the condensed consolidated statements of income and other comprehensive income. PGE estimates the portion of the non-service components of net periodic pension and postretirement benefit costs that is eligible for deferral for ratemaking purposes, to be $3 million for the twelve month period ending December 31, 2018, and is deemed to have an immaterial impact on the Company's consolidated financial position and consolidated results of operations.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $6 million as of December 31, 2017 and December 31, 2016. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2017	2016	2015
Balance as of beginning of year	$ 6	$ 6	$ 6
Increase in provision	6	5	6
Amounts written off, less recoveries	(6)	(5)	(6)
Balance as of end of year	$ 6	$ 6	$ 6

Trust Accounts

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

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

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

	Nuclear Decommissioning Trust		Non-Qualified Benefit Plan Trust	
	2017	2016	2017	2016
Cash equivalents	$ 25	$ 21	$ 1	$ 1
Marketable securities, at fair value:				
Equity securities	—	—	7	6
Debt securities	17	20	1	1
Insurance contracts, at cash surrender value	—	—	28	26
	$ 42	$ 41	$ 37	$ 34

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

Other Current Assets and Accrued Expenses and Other Current Liabilities

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

	As of December 31,	
	2017	**2016**
Other current assets:		
Prepaid expenses	$ 50	$ 48
Margin deposits	11	8
Assets from price risk management activities	6	18
Other	6	3
	$ 73	$ 77
Accrued expenses and other current liabilities:		
Regulatory liabilities—current	$ 31	$ 51
Accrued employee compensation and benefits	60	52
Accrued dividends payable	31	30
Accrued interest payable	27	25
Accrued taxes payable	31	25
Other	61	71
	$ 241	$ 254

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company's consolidated balance sheets, for which it is practicable to estimate fair value as of December 31, 2017 and 2016, and then classifies these financial assets and liabilities based on a fair value hierarchy that is used to prioritize the inputs to the valuation techniques used to measure fair value. The three levels and application to the Company are discussed below.

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

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

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

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. Assets measured at fair value using net asset value (NAV) as a practical expedient are not categorized in the fair value hierarchy. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all of its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the years ended December 31, 2017 and 2016, except those presented in this note.

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

	As of December 31, 2017				
	Level 1	**Level 2**	**Level 3**	**Other[2]**	**Total**
Assets:					
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	$ 4	$ 7	$ —	$ —	$ 11
Corporate credit	—	6	—	—	6
Money market funds measured at NAV [2]	—	—	—	25	25
Non-qualified benefit plan trust: [3]					
Money market funds	1	—	—	—	1
Equity securities—domestic	7	—	—	—	7
Debt securities—domestic government	1	—	—	—	1
Investments measured at NAV: [2]					
Collective trust—domestic equity	—	—	—	—	—
Assets from price risk management activities: [1] [4]					
Electricity	—	3	—	—	3
Natural gas	—	3	—	—	3
	$ 13	$ 19	$ —	$ 25	$ 57
Liabilities - Liabilities from price risk management activities: [1] [4]					
Electricity	$ —	$ 5	$ 130	$ —	$ 135
Natural gas	—	66	9	—	75
	$ —	$ 71	$ 139	$ —	$ 210

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $28 million, which are recorded at cash surrender value.
(4) For further information, see Note 5, Price Risk Management.

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

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

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

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

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

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

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

The NQBP trust is invested in exchange traded government money market funds and is classified as Level 1 in the fair value hierarchy due to the availability of quoted prices in published exchanges such as NASDAQ and the NYSE. The money market fund in the NDT is valued at NAV as a practical expedient and is not included in the fair value hierarchy.

Common and collective trust funds—PGE invests in common and collective trust funds that invests in equity securities. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value as a practical expedient. The funds allow for daily liquidity with appropriate notice. Common and collective trusts are not classified in the fair value hierarchy as they are valued at NAV as a practical expedient. All collective trusts for the NQBP were liquidated during 2017.

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

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

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

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

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
As of December 31, 2017:							
Electricity physical forward	$ —	$ 130	Discounted cash flow	Electricity forward price (per MWh)	$ 7.79	$ 41.23	$ 30.95
Natural gas financial swaps	—	9	Discounted cash flow	Natural gas forward price (per Dth)	1.26	2.92	1.90
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	7.79	29.74	21.74
	$ —	$ 139					
As of December 31, 2016:							
Electricity physical forward	$ —	$ 112	Discounted cash flow	Electricity forward price (per MWh)	$ 14.25	$ 54.73	$ 38.18
Natural gas financial swaps	1	9	Discounted cash flow	Natural gas forward price (per Dth)	1.85	4.92	2.64
Electricity financial futures	1	—	Discounted cash flow	Electricity forward price (per MWh)	8.57	33.60	25.10
	$ 2	$ 121					

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

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

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

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

	Years Ended December 31, 2017	Years Ended December 31, 2016
Net liabilities from price risk management activities as of beginning of year	$ 119	$ 119
Net realized and unrealized losses *	35	11
Net transfers in to Level 3 from Level 2	—	(1)
Net transfers out of Level 3 to Level 2	(15)	(10)
Net liabilities from price risk management activities as of end of year	$ 139	$ 119
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 41	$ 11

* Includes $6 million in net realized losses in 2017 and none in 2016.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. During the year ended December 31, 2017, there were no transfers into Level 3 from Level 2, as reflected in the table above. During 2016, there was $1 million transferred into Level 3. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its derivative instruments. Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

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

As of December 31, 2017, the carrying amount of PGE's long-term debt was $2,426 million, net of $10 million of unamortized debt expense, and its estimated aggregate fair value was $2,829 million, all of which is classified as Level 2 in the fair value hierarchy. As of December 31, 2016, the carrying amount of PGE's long-term debt was $2,350 million, net of $11 million of unamortized debt expense, with an estimated aggregate fair value of $2,693 million, consisting of $2,543 million and $150 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy.

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

NOTE 5: PRICE RISK MANAGEMENT

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

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

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

	As of December 31,	
	2017	2016
Current assets:		
Commodity contracts:		
Electricity	$ 3	$ 6
Natural gas	3	12
Total current derivative assets	6 (1)	18 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	—	1
Natural gas	—	4
Total noncurrent derivative assets	— (2)	5 (2)
Total derivative assets not designated as hedging instruments	$ 6	$ 23
Total derivative assets	$ 6	$ 23
Current liabilities:		
Commodity contracts:		
Electricity	$ 13	$ 12
Natural gas	46	32
Total current derivative liabilities	59	44
Noncurrent liabilities:		
Commodity contracts:		
Electricity	122	106
Natural gas	29	19
Total noncurrent derivative liabilities	151	125
Total derivative liabilities not designated as hedging instruments	$ 210	$ 169
Total derivative liabilities	$ 210	$ 169

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

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

	As of December 31,					
	2017			2016		
Commodity contracts:						
Electricity		7	MWh		8	MWh
Natural gas		114	Dth		107	Dth
Foreign currency exchange	$	21	Canadian	$	22	Canadian

PGE has elected to report gross on the consolidated balance sheets the positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement. In the case of default on, or termination of, any contract under the master netting arrangements, such agreements provide for the net settlement of all related contractual obligations with a given counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit. As of December 31, 2017 and 2016, gross amounts included as Price risk management liabilities subject to master netting agreements were $136 million and $115 million, respectively, for which PGE posted collateral of $11 million for 2017 and 2016, which consisted entirely of letters of credit. As of December 31, 2017, of the gross amounts included, $130 million was for electricity and $6 million was for natural gas compared to $112 million for electricity and $3 million for natural gas recognized as of December 31, 2016.

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

	Years Ended December 31,					
	2017		2016		2015	
Commodity contracts:						
Electricity	$	41	$	34	$	72
Natural Gas		85		(56)		103
Foreign currency exchange		(1)		—		1

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the consolidated statements of income by the effects of regulatory accounting. Net losses of $82 million, net gains of $13 million, and net losses of $160 million for the years ended December 31, 2017, 2016, and 2015, respectively, have been offset in Net income.

Assuming no changes in market prices and interest rates, the following table presents the year in which the net unrealized loss recorded as of December 31, 2017 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2018		2019		2020		2021		2022		Thereafter		Total	
Commodity contracts:														
Electricity	$	10	$	8	$	8	$	8	$	7	$	91	$	132
Natural gas		43		20		7		2		—		—		72
Net unrealized loss	$	53	$	28	$	15	$	10	$	7	$	91	$	204

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

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2017 was $205 million, for which the Company had posted $31 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2017, the cash requirement to either post as collateral or settle the instruments immediately would have been $202 million. As of December 31, 2017, PGE had no posted cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as Margin deposits included in Other current assets on the Company's consolidated balance sheet.

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

	As of December 31,	
	2017	**2016**
Assets from price risk management activities:		
Counterparty A	39%	22%
Counterparty B	12	17
Counterparty C	3	12
	54%	51%
Liabilities from price risk management activities:		
Counterparty D	62%	66%
	62%	66%

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

NOTE 6: REGULATORY ASSETS AND LIABILITIES

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

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

	Weighted Average Remaining Life [1]	As of December 31,			
		2017		2016	
		Current	Noncurrent	Current	Noncurrent
Regulatory assets:					
Price risk management [2]	6 years	$ 53	$ 151	$ 26	$ 120
Pension and other postretirement plans [2]	[3]	—	218	—	235
Deferred income taxes [6]	[4]	—	—	—	86
Debt issuance costs [2]	6 years	—	19	—	22
Other [5]	Various	9	50	10	35
Total regulatory assets		$ 62	$ 438	$ 36	$ 498
Regulatory liabilities:					
Asset retirement removal costs [6]	[4]	$ —	$ 933	$ —	$ 887
Deferred income taxes [6]	[4]	—	277	—	—
Trojan decommissioning activities	5 years	3	—	18	—
Asset retirement obligations [6]	[4]	—	52	—	49
Other	Various	28	26	33	22
Total regulatory liabilities		$ 31 [7]	$ 1,288	$ 51 [7]	$ 958

(1) As of December 31, 2017.
(2) Does not include a return on investment.
(3) Recovery expected over the average service life of employees.
(4) Recovery or refund expected over the estimated lives of the net balance.
(5) Of the total other unamortized regulatory asset balances, a return is recorded on $51 million and $44 million as of December 31, 2017 and 2016, respectively.
(6) Included in rate base for ratemaking purposes.
(7) Included in Accrued expenses and other current liabilities on the consolidated balance sheets.

As of December 31, 2017, PGE had regulatory assets of $51 million earning a return on investment at the following rates: i) $14 million earning a return by inclusion in rate base; ii) $25 million at the approved rate for deferred accounts under amortization, ranging from 1.47% to 2.38%, depending on the year of approval; iii) $10 million at PGE's 2017 cost of capital of 7.51%, and iv) $2 million at a rate of the 5-year Treasury rate plus 100 basis points, which currently equates to 2.87%.

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

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

Deferred income taxes represents income tax benefits primarily from property-related timing differences that previously flowed to customers and will be included in customer prices when the temporary differences reverse. In 2017, the net regulatory liability was increased by $357 million as the Company deferred the impact of re-measuring accumulated deferred income taxes pursuant to the enactment of the Tax Cuts and Jobs Act (the TCJA) on December 22, 2017. PGE has proposed to defer and refund the net benefits of the change in tax law under a deferral application filed with the OPUC on December 29, 2017. Substantially all of the amounts deferred under the proposed deferral application are subject to tax normalization rules that require that the impact to the results of operations of amortizing the excess deferred income tax balance cannot occur more rapidly than would have occurred before the change in tax law. The Company plans to use the average rate assumption method to account for the refund to customers. For further information, see Note 11, Income Taxes.

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

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

Trojan decommissioning activities represents proceeds received for the settlement of a legal matter concerning the reimbursement from the United States Department of Energy (USDOE) of certain monitoring costs incurred related to spent nuclear fuel at Trojan, as well as ongoing costs and collections associated with decommissioning activities.

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

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2017	**2016**
Trojan decommissioning activities	$ 45	$ 44
Utility plant	109	105
Non-utility property	13	12
Asset retirement obligations	$ 167	$ 161

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

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

A trial before the U.S. Court of Federal Claims concluded in 2012, with the Court issuing a judgment awarding certain damages to the Plaintiffs. The settlement agreement also provides for a process to submit claims for allowable costs for the periods subsequent to 2009, including an extension to cover costs through 2019. Pursuant to this process, the USDOE has reimbursed the Plaintiffs $85 million for costs incurred through 2016 resulting from USDOE delays in accepting spent nuclear fuel.

PGE has received proceeds of $53 million related to its share in this legal matter. The settlement amounts received were recorded as a regulatory liability to offset amounts previously collected in relation to Trojan decommissioning activities. In December 2014, the OPUC issued an order on the Company's 2015 GRC, authorizing the return of $50 million of the proceeds received related to this legal matter to customers over a three-year period beginning January 1, 2015. PGE will return the remaining $3 million to customers in 2018.

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

Utility plant represents AROs that have been recognized for the Company's thermal and wind generation sites, distribution and transmission assets, the disposal of which is governed by environmental regulation. During 2017, the Company recorded an overall increase in AROs, including Trojan, of $6 million, with the change comprised of an increase to revisions in estimated cash flows and incurred liabilities of $2 million, accretion of $7 million, and a reduction of $3 million due to settled liabilities.

In 2015, the Company recorded an increase to the Colstrip ARO in the amount of $17 million, as Colstrip utilizes wet scrubbers and a number of settlement ponds that will require upgrading or closure to meet new EPA regulatory requirements. PGE plans to seek recovery in customer prices of the incremental costs associated with the final EPA rules.

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

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

	Years Ended December 31,		
	2017	2016	2015
Balance as of beginning of year	$ 161	$ 151	$ 116
Liabilities incurred	2	1	2
Liabilities settled	(3)	(3)	(4)
Accretion expense	7	7	7
Revisions in estimated cash flows	—	5	30
Balance as of end of year	$ 167	$ 161	$ 151

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

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

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

NOTE 8: CREDIT FACILITIES

As of December 31, 2017, PGE had a $500 million revolving credit facility scheduled to expire in November 2021.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. The revolving credit facility requires annual fees based on PGE's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2017, PGE was in compliance with this covenant with a 51.8% debt to total capital ratio.

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

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

PGE had no borrowings outstanding and there was no commercial paper or letters of credit issued under the revolving credit facility as of December 31, 2017. As a result, as of December 31, 2017, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities that provide capacity up to a total of $220 million under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, $67 million of letters of credit was outstanding, as of December 31, 2017.

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt in an aggregate amount up to $900 million through February 6, 2020.

Short-term borrowings under these credit facilities and related interest rates are reflected in the following table (dollars in millions). The Company had no short-term borrowings during 2017.

	Years Ended December 31,		
	2017	2016	2015
Average daily amount of short-term debt outstanding	$ —	$ 1	$ —
Weighted daily average interest rate *	—%	0.7%	0.6%
Maximum amount outstanding during the year	$ —	$ 23	$ 11

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

NOTE 9: LONG-TERM DEBT

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

	As of December 31,	
	2017	2016
First Mortgage Bonds, rates range from 2.51% to 9.31%, with a weighted average rate of 5.03% in 2017 and 4.86% in 2016, due at various dates through 2048	$ 2,315	$ 2,090
Unsecured term bank loans, variable rates of approximately 1.87% at 11/27/2017 and 1.37% at 12/31/2016	—	150
Pollution Control Revenue Bonds, 5% rate, due 2033	142	142
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Total long-term debt	2,436	2,361
Less: Unamortized debt expense	(10)	(11)
Less: Current portion of long-term debt	—	(150)
Long-term debt, net of current portion	$ 2,426	$ 2,200

First Mortgage Bonds and Unsecured term bank loans—During 2017, PGE issued a total of $225 million of FMBs and repaid long-term debt, in an aggregate amount of $150 million.

In 2017, the Company issued a total of $225 million at an interest rate of 3.98%. PGE drew $75 million in August with a maturity of 2048 and drew the remaining $150 million in November with a maturity of 2047.

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

In 2017, PGE repaid an unsecured credit agreement under which it had borrowed $150 million from certain financial institutions. PGE repaid the loan in three separate payments as follows:

- $50 million on August 21, 2017;
- $25 million on October 30, 2017; and
- $75 million on November 27, 2017.

The term loan interest rates were set at the beginning of the interest period for periods of 1-month, 3-months, or 6-months, as selected by PGE and are based on the London Interbank Offered Rate (LIBOR) plus 63 basis points. The final rate was 1.87% as of November 27, 2017, with no other fees.

Pollution Control Revenue Bonds—The Company has the option to remarket through 2033 the $21 million of Pollution Control Revenue Bonds (PCBs) held by PGE as of December 31, 2017. At the time of any remarketing, the Company can choose a new interest rate period that could be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing. The PCBs could be backed by FMBs or a bank letter of credit depending on market conditions. Interest is payable semi-annually on PCBs.

As of December 31, 2017, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2018	$	—
2019		300
2020		—
2021		160
2022		—
Thereafter		1,976
	$	2,436

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

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

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

PGE contributed $2 million to the pension plan in 2017, and made no contributions in 2016 or 2015. PGE expects to contribute $21 million to the pension plan in 2018.

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

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

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

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

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

	2017			2016		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	$ 17	$ 20	$ 37	$ 16	$ 18	$ 34
Non-qualified benefit plan liabilities *	25	81	106	25	80	105

* For the NQBP, excludes the current portion of $2 million in 2017 and 2016, respectively, which are classified in Other current liabilities in the consolidated balance sheets.

See "*Trust Accounts*" in Note 3, Balance Sheet Components, for information on the NQBP trust.

Investment Policy and Asset Allocation—The Board of Directors of PGE appoints an Investment Committee, which is comprised of certain members of management from the Company, and establishes the Company's asset allocation. The Investment Committee is then responsible for implementation of the asset allocation and oversight of the benefit plan investments. The Company's investment policy for its pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities, and other alternative investments. Asset classes are regularly rebalanced to ensure asset allocations remain within prescribed parameters.

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

	As of December 31,			
	2017		2016	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	68%	67%	68%	67%
Debt securities	32	33	32	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	63%	62%	60%	62%
Debt securities	37	38	40	38
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	18%	12%	15%	11%
Debt securities	6	12	7	11
Insurance contracts	76	76	78	78
Total	100%	100%	100%	100%

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

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

Assets measured at fair value using net asset value (NAV) as a practical expedient are not categorized in the fair value hierarchy. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements.

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

	Level 1	Level 2	Level 3	Other *	Total
As of December 31, 2017:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 83	$ —	$ —	$ —	$ 83
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	528	528
Private equity funds	—	—	—	13	13
	$ 83	$ —	$ —	$ 546	$ 629
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$ —	$ —	$ —	$ 3
Equity securities:					
Domestic	—	3	—	—	3
International	10	—	—	—	10
Debt securities—Domestic government	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	4	4
Collective trust funds	—	—	—	8	8
	$ 13	$ 8	$ —	$ 12	$ 33
As of December 31, 2016:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 52	$ —	$ —	$ —	$ 52
Investments measured at NAV:					
Money market funds	—	—	—	6	6
Collective trust funds	—	—	—	483	483
Private equity funds	—	—	—	18	18
	$ 52	$ —	$ —	$ 507	$ 559
Other Postretirement Benefit Plans assets:					
Money market funds	$ 4	$ —	$ —	$ —	$ 4
Equity securities:					
Domestic	—	3	—	—	3
International	8	—	—	—	8
Debt securities—Domestic government	—	4	—	—	4
Investments measured at NAV:					
Money market funds	—	—	—	4	4
Collective trust funds	$ —	$ —	$ —	$ 7	$ 7
	$ 12	$ 7	$ —	$ 11	$ 30

* Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.

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

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

Equity securities—Equity mutual fund and common stock securities are classified as Level 1 securities as pricing inputs are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. Mutual fund assets included in separately managed accounts are classified as Level 2 securities due to pricing inputs that are directly or indirectly observable in the marketplace.

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

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

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

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and NQBP as of and for the years ended December 31, 2017 and 2016. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2017	2016	2017	2016	2017	2016
Benefit obligation:						
As of January 1	$ 797	$ 758	$ 73	$ 81	$ 27	$ 27
Service cost	17	16	2	2	—	—
Interest cost	33	33	3	4	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial loss (gain)	60	26	3	(11)	1	1
Contractual termination benefits	—	—	1	—	—	—
Benefit payments	(36)	(34)	(6)	(5)	(2)	(2)
Administrative expenses	(2)	(2)	—	—	—	—
As of December 31	$ 869	$ 797	$ 78	$ 73	$ 27	$ 27
Fair value of plan assets:						
As of January 1	$ 559	$ 550	$ 30	$ 30	$ 16	$ 15
Actual return on plan assets	106	45	4	1	1	1
Company contributions	2	—	3	2	2	2
Participants' contributions	—	—	2	2	—	—
Benefit payments	(36)	(34)	(6)	(5)	(2)	(2)
Administrative expenses	(2)	(2)	—	—	—	—
As of December 31	$ 629	$ 559	$ 33	$ 30	$ 17	$ 16
Unfunded position as of December 31	$ (240)	$ (238)	$ (45)	$ (43)	$ (10)	$ (11)
Accumulated benefit plan obligation as of December 31	$ 778	$ 714	N/A	N/A	$ 27	$ 27
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 17	$ 16
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(240)	(238)	(45)	(43)	(25)	(25)
Net liability	$ (240)	$ (238)	$ (45)	$ (43)	$ (10)	$ (11)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ (4)	$ 21	$ —	$ (10)	$ 1	$ 1
Amortization of net actuarial loss	(13)	(14)	—	—	(1)	(1)
Amortization of prior service cost	—	—	—	(1)	—	—
	$ (17)	$ 7	$ —	$ (11)	$ —	$ —
Amounts included in AOCL*:						
Net actuarial loss (gain)	$ 218	$ 236	$ (1)	$ (2)	$ 13	$ 13
Prior service cost	—	—	—	1	—	—
	$ 218	$ 236	$ (1)	$ (1)	$ 13	$ 13

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2017	2016	2017	2016	2017	2016
Assumptions used:						
Discount rate for benefit obligation	3.65%	4.17%	3.42%-3.70%	3.75%-4.23%	3.65%	4.17%
Discount rate for benefit cost	4.17%	4.36%	3.75%-4.23%	3.90%-4.45%	4.17%	4.36%
Weighted average rate of compensation increase for benefit obligation	4.58%	3.65%	4.58%	4.58%	N/A	N/A
Weighted average rate of compensation increase for benefit cost	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets for benefit obligation	7.50%	7.50%	6.26%	6.26%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	7.50%	7.50%	6.26%	6.29%	N/A	N/A

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

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

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Service cost	$ 17	$ 16	$ 18	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	33	33	31	3	4	3	1	1	1
Expected return on plan assets	(42)	(40)	(40)	(2)	(2)	(2)	—	—	—
Amortization of prior service cost	—	—	—	—	1	1	—	—	—
Amortization of net actuarial loss	13	14	20	—	—	1	1	1	1
Net periodic benefit cost	$ 21	$ 23	$ 29	$ 3	$ 5	$ 5	$ 2	$ 2	$ 2

PGE estimates that $18 million will be amortized from AOCL into net periodic benefit cost in 2018, consisting of a net actuarial loss of $17 million for pension benefits and $1 million for non-qualified benefits. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

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

	Payments Due					
	2018	2019	2020	2021	2022	2023 - 2026
Defined benefit pension plan	$ 39	$ 41	$ 42	$ 43	$ 44	$ 234
Other postretirement benefits	5	5	5	4	5	22
Non-qualified benefit plans	2	3	2	2	2	10
Total	$ 46	$ 49	$ 49	$ 49	$ 51	$ 266

All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns, with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth.

Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

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

- For 2017, 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2018, decreasing to 6.0% in 2019, then decreasing 0.25% per year thereafter, reaching 5.0% in 2023;
- For 2016, 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017, decreasing to 6.5% in 2018, then decreasing 0.25% per year thereafter, reaching 5.0% in 2023; and
- For 2015, 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2016, decreasing to 6.0% in 2017, then decreasing 0.25% per year thereafter, reaching 5.0% in 2021.

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

401(k) Retirement Savings Plan

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

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

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $21 million in 2017, $19 million in 2016, and $17 million in 2015.

NOTE 11: INCOME TAXES

On December 22, 2017, the TCJA was enacted and signed into law by the President of the United States with substantially all of the provisions of the TCJA having an effective date of January 1, 2018. Among other provisions, the reduction of the federal corporate tax rate from 35% to 21%, which required the Company to remeasure its existing deferred income tax balances as of December 31, 2017, had the most impact on PGE's financial condition. As a result of the Company's remeasurement, net deferred tax liabilities on the Company's consolidated balance sheets were reduced by $340 million.

Of the remeasurement amount, $357 million has been deferred as a regulatory liability and is expected to be refunded to customers over time. These deferred tax items relate primarily to Electric utility plant and other rate base items subject to tax normalization rules that require the benefits to be passed on to customers through future prices over the remaining useful life of the underlying assets for which the deferred income taxes relate. The Company plans to use the average rate assumption method to account for the refund to customers. A portion of the remeasurement is not subject to tax normalization rules and will be amortized over time.

The remaining and offsetting remeasurement amount of $17 million represents a reduction to net deferred tax assets related to other business items, primarily comprised of deferred tax assets related to the Company's NQBPs. The

Company has recorded a $17 million charge to the results of operations, reflected as an increase in Income tax expense in the Company's consolidated statements of income for the period ended December 31, 2017.

Based on the Company's interpretations of the TCJA as of December 31, 2017, PGE believes it has substantially completed its analysis of the tax effects of the TCJA and has reflected such effects in the remeasurement amounts recorded. However, PGE has not yet finalized its federal tax returns for 2017 and also expects regulatory bodies, such as the U.S. Department of the Treasury, Internal Revenue Service, and OPUC to issue additional guidance or orders in 2018 that may result in changes to the Company's previously finalized analysis of the TCJA. Such changes could result in material changes to the ultimate impact of the TCJA on PGE's financial condition, results of operations, and cash flows.

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

	Years Ended December 31,		
	2017	2016	2015
Current:			
Federal	$ 4	$ 10	$ 4
State and local	12	3	1
	16	13	5
Deferred:			
Federal	61	23	26
State and local	9	14	14
	70	37	40
Income tax expense	$ 86	$ 50	$ 45

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

	Years Ended December 31,		
	2017	2016	2015
Federal statutory tax rate	35.0%	35.0%	35.0%
Federal tax credits(1)	(14.0)	(18.2)	(19.0)
Change in federal tax law(2)	6.1	—	—
State and local taxes, net of federal tax benefit	5.0	4.8	4.2
Flow through depreciation and cost basis differences	1.5	0.2	—
Other	(2.1)	(1.2)	0.5
Effective tax rate	31.5%	20.6%	20.7%

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

(2) Includes a $17 million increase to Income tax expense related to the remeasurement of deferred income taxes as a result of the enacted tax rate change under the TCJA.

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

	As of December 31,	
	2017	2016
Deferred income tax assets:		
Employee benefits	$ 128	$ 181
Price risk management	56	59
Regulatory liabilities	14	29
Tax credits	50	56
Other	4	5
Total deferred income tax assets	252	330
Deferred income tax liabilities:		
Depreciation and amortization	496	829
Regulatory assets	132	170
Other	—	—
Total deferred income tax liabilities	628	999
Deferred income tax liability, net	$ (376)	$ (669)

As of December 31, 2017, PGE has federal credit carryforwards of $50 million, consisting of PTCs, which will expire at various dates through 2037. PGE has analyzed the provisions of the TCJA and its effects on the Company's deferred income tax assets, and PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2017 and 2016 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2017 and 2016, PGE had no unrecognized tax benefits.

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

NOTE 12: EQUITY-BASED PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock (based on fair value on the purchase date) or 1,500 shares, whichever is less. Two, six-month offering periods occur annually, January 1 through June 30 and July 1 through December 31, during which eligible employees may contribute toward the purchase of shares of PGE common stock. Purchases occur the last day of the offering period, at a price equal to 95% of the fair value of the stock on the purchase date. As of December 31, 2017, there were 339,542 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

PGE has a Dividend Reinvestment and Direct Stock Purchase Plan (DRIP), under which a total of 2,500,000 shares of the Company's common stock may be issued. Under the DRIP, investors may elect to buy shares of the Company's common stock or elect to reinvest cash dividends in additional shares of the Company's common stock. As of December 31, 2017, there were 2,470,052 shares available for future issuance pursuant to the DRIP.

Equity Forward Sale Agreement

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

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

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

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

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2014	463,893	$ 28.96
Granted	181,797	34.77
Forfeited	(14,988)	34.10
Vested	(187,709)	25.82
Outstanding as of December 31, 2015	442,993	32.84
Granted	193,734	35.89
Forfeited	(3,044)	28.62
Vested	(174,891)	31.47
Outstanding as of December 31, 2016	458,792	34.68
Granted	202,145	41.96
Forfeited	(64,840)	39.57
Vested	(196,721)	31.78
Outstanding as of December 31, 2017	399,376	37.98

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 3,229,476 shares remain available for future issuance as of December 31, 2017.

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

Time-based RSUs vest in either equal installments over a one-year period on the last day of each calendar quarter, over a three-year period on each anniversary of the grant date, or at the end of a three-year period following the grant date. The fair value of time-based RSUs is measured based on the closing price of PGE common stock on the date of grant and charged to compensation expense on a straight-line basis over the requisite service period for the entire award. The total value of time-based RSUs vested was less than $1 million for the years ended December 31, 2017, 2016, and 2015.

Performance-based RSUs vest if performance goals are met at the end of a three-year performance period. Grants are based on three equally-weighted metrics: i) return on equity relative to allowed return on equity; ii) regulated asset base growth (applicable only for those grants made prior to 2017); and iii) a relative total shareholder return (TSR) of PGE's common stock as compared to an index of peer companies during the performance period. Vesting of performance-based RSUs is calculated by multiplying the number of units granted by a performance percentage determined by the Compensation and Human Resources Committee of PGE's Board of Directors (Committee). The performance percentage is calculated based on the extent to which the performance goals are met. In accordance with the Plan, however, the Committee may disregard or offset the effect of extraordinary, unusual or non-recurring items in determining results relative to these goals. Based on the attainment of the performance goals, the awards can range from zero to 150% of the grant.

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

	2017	2016
Risk-free interest rate	1.5%	0.9%
Expected dividend yield	—%	—%
Expected term (in years)	3.0	3.0
Volatility	15.6% - 22.9%	14.5% - 25.9%

The fair value of performance-based RSUs is charged to compensation expense on a straight-line basis over the requisite service period for the entire award based on the number of shares expected to vest. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the weighted average vesting of 107.0%, 120.8%, and 118.2% of awarded performance-based RSUs for the respective 2017, 2016, and 2015 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $6 million for the year ended December 31, 2017, $5 million for 2016, and $4 million for 2015.

Stock-based compensation, included in Administrative and other expense in the consolidated statements of income, was $7 million for the year ended December 31, 2017, and $6 million for 2016, and 2015. Such amounts differ from those reported in the consolidated statements of equity for Stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. Not included in Administrative and other expenses in the consolidated statements of income, is the net impact from these income tax payments, partially offset by the issuance of DERs, resulting in a charge to equity of $3 million in 2017, and $2 million in 2016 and 2015.

As of December 31, 2017, unrecognized stock-based compensation expense was $7 million, of which approximately $5 million and $2 million is expected to be expensed in 2018 and 2019, respectively. No stock-based compensation costs have been capitalized and the Plan had no material impact on cash flows for the years ended December 31, 2017, 2016, or 2015.

NOTE 14: EARNINGS PER SHARE

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

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

	Years Ended December 31,		
	2017	2016	2015
Weighted average common shares outstanding—basic	89,056	88,896	84,180
Dilutive effect of potential common shares	120	158	161
Weighted average common shares outstanding—diluted	89,176	89,054	84,341

NOTE 15: COMMITMENTS AND GUARANTEES

Purchase Commitments

As of December 31, 2017, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2018	2019	2020	2021	2022	Thereafter	Total
Capital and other purchase commitments	$ 191	$ 2	$ 10	$ 2	$ 2	$ 58	$ 265
Purchased power and fuel:							
Electricity purchases	156	156	201	200	187	1,733	2,633
Capacity contracts	6	5	4	4	4	8	31
Public utility districts	9	17	16	16	15	85	158
Natural gas	51	35	28	25	24	140	303
Coal and transportation	15	5	—	—	—	—	20
Total	$ 428	$ 220	$ 259	$ 247	$ 232	$ 2,024	$ 3,410

Capital and other purchase commitments—Certain commitments have been made for 2018 and beyond that include those related to hydro licenses, upgrades to generation, distribution, and transmission facilities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase agreements with counterparties, which expire at varying dates through 2044, and power capacity contracts through 2024.

Public utility districts—PGE has long-term power purchase agreements with certain public utility districts including, Grant County PUD for the Priest Rapids and Wanapum projects, and Douglas County PUD for the Wells project, in the state of Washington. Under the agreements, the Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether or not they are operable. In addition, although PGE's current agreement with Douglas County ends on August 31, 2018, a new contract becomes effective on September 1, 2018 that does not require contributions to Douglas County debt obligation or other costs, including the operation and maintenance costs of the projects. The new contract requires monthly payments for capacity that will not vary with annual project generation provided to PGE. The Company has estimated the capacity payments, which are subject to annual adjustments based on Douglas loads, and included the estimated amounts in the table above. The future minimum payments for the public utility districts in the preceding table reflect the principal and capacity payments only and do not include interest, operation, or maintenance expenses.

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

	Revenue Bonds as of December 31, 2017	PGE's Share as of December 31, 2017		Contract Expiration	PGE Cost, including Debt Service		
		Output	Capacity		2017	2016	2015
			(in MW)				
Priest Rapids and Wanapum	$ 1,269	8.6%	163	2052	$ 16	$ 16	$ 18
Wells	160	19.4	150	2018	11	10	10
Portland Hydro	—	—	—	2017	1	1	2

The agreements for Priest Rapids, Wanapum, and Wells provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of the output and operating and debt service costs of the defaulting purchaser. For Wells, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage through August 2018, after which PGE would be responsible for a pro-rata portion of the defaulting purchaser's share with no limitation, regardless of the reason for any default. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any of the public utility district's outstanding debt for the portion of the project that benefits tax exempt purchasers.

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

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

Lease Obligations

As of December 31, 2017, PGE's estimated future minimum lease payments pursuant to capital, build-to-suit, and operating leases for the following five years and thereafter are as follows (in millions):

	Future Minimum Lease Payments		
	Capital Leases	**Build-to-Suit**	**Operating Leases**
2018	$ 7	$ —	$ 9
2019	6	15	8
2020	6	15	6
2021	6	14	6
2022	5	14	8
Thereafter	72	260	165
Total minimum lease payments	$ 102	$ 318	$ 202
Less imputed interest	51		
Present value of net minimum lease payments	$ 51		
Less current portion	2		
Non-current portion	$ 49		

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

As of December 31, 2017, a capital lease asset of $57 million was reflected within Electric utility plant and accumulated amortization of such assets of $6 million was reflected within Accumulated depreciation and amortization in the table above. The present value of the future minimum lease payments due under the agreement included $2 million within Accrued expenses and other current liabilities and $49 million in Other noncurrent liabilities on the consolidated balance sheets. For ratemaking purposes capital leases are treated as operating leases; therefore, in accordance with the accounting rules for regulated operations, the amortization of the leased asset is based on the rental payments recovered from customers. Also for ratemaking purposes, such rental payments were capitalized to the Carty project prior to its in service date of July 29, 2016 and, as a result, amortization of the leased asset of $2 million and interest expense of $3 million was capitalized to CWIP. Beginning August 1, 2016, amortization of the leased asset of $1 million and interest expense of $2 million has been recorded to Purchased power and fuel expense in the consolidated statements of income through December 31, 2016. For the year ended December 31, 2017, amortization of the leased asset of $3 million and interest expense of $4 million has been recorded to Purchased power and fuel expense in the consolidated statements of income.

Build-to-suit—PGE has entered into a 30-year lease agreement with a local natural gas company, NW Natural, to expand their current natural gas storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-mile pipeline, which will be designed to provide no-notice storage and transportation services to PGE's PW1, PW2, and Beaver natural gas-fired generating plants. Pursuant to the agreement, on September 30, 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which the gas company estimates will be completed during the winter of 2018-2019, at a cost of approximately $132 million. Due to the level of PGE's involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE has recorded $108 million to CWIP and a corresponding liability for the same amount to Other noncurrent liabilities in the consolidated balance sheets as of December 31, 2017. In 2016, PGE recorded $21 million to CWIP and a corresponding liability for the same amount to Other noncurrent liabilities in the consolidated balance sheets as of

December 31, 2016. Upon completion of the facility, PGE will assess whether the assets and liabilities qualify as a successful sale-leaseback transaction in which the asset and liability are removed and accounted for as either a capital or operating lease. The table above reflects PGE's estimated future minimum lease payments pursuant to the agreement based on estimated costs and assumes three 10-year renewable options are exercised.

Operating leases—PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities that expire in various years, including the Port of St. Helens land lease, which expires in 2096 and covers the location of PW1, PW2, and Beaver. Rent expense was $9 million in 2017, and $10 million in 2016 and 2015.

The future minimum operating lease payments presented is net of sublease income of $4 million in each of 2018, 2019, 2020, and 2021; and $2 million in 2022. Sublease income was $4 million in 2017 and 2016, and $3 million in 2015.

Guarantees

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2017, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the consolidated balance sheets with respect to these indemnities.

NOTE 16: JOINTLY-OWNED PLANT

As of December 31, 2017, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation*	Construction Work In Progress
Boardman	90.00%	1980	$ 515	$ 426	$ —
Colstrip	20.00	1986	546	351	5
Pelton/Round Butte	66.67	1958 / 1964	251	68	7
Total			$ 1,312	$ 845	$ 12

* Excludes AROs and accumulated asset retirement removal costs.

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

NOTE 17: CONTINGENCIES

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

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

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

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

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

Carty

In 2013, PGE entered into a turnkey engineering, procurement, and construction agreement (Construction Agreement) with Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership (collectively, the “Contractor”), affiliates of Abengoa S.A. - for the construction of the Carty natural gas-fired generating plant (Carty) located in Eastern Oregon. Liberty Mutual Insurance Company and Zurich American Insurance Company (together, the “Sureties”) provided a performance bond of $145.6 million (Performance Bond) in connection with the Construction Agreement.

In December 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Following termination of the Construction Agreement, PGE brought on new contractors and construction resumed.

Carty was placed into service on July 29, 2016 and the Company began collecting its revenue requirement in customer prices on August 1, 2016, as authorized by the OPUC, based on the approved capital cost of $514 million. Actual costs for the construction of Carty exceeded the approved amount and, as of December 31, 2017, PGE has capitalized $637 million to Electric utility plant.

As the final construction cost exceeded the amount authorized by the OPUC, higher interest and depreciation expense than allowed in the Company’s revenue requirement has resulted. These incremental expenses are recognized in the Company’s current results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP.

As actual project costs for Carty have exceeded $514 million, the Company has incurred a higher cost of service than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation, interest expense and legal expenses. Such incremental expenses were $14 million and $3 million for the year ended December 31, 2017 and 2016, respectively. Any amounts approved by the OPUC for recovery under the deferral filing would be recognized in earnings in the period of such approval.

Actual costs do not reflect any offsetting amounts that may be received from the Sureties, pursuant to the Performance Bond. The amounts recorded also exclude $8 million of liens and claims filed for goods and services provided under contracts with the former Contractor that remain in dispute. The Company believes these liens and claims are invalid and is contesting the liens and claims in the courts.

The incremental costs resulted from various matters relating to the resumption of construction activities following the termination of the Construction Agreement, including, among other things, completing the remaining construction work, correcting deficiencies and defects in work performed by the former Contractor, determining the remaining scope of construction, preparing work plans for contractors, identifying new contractors, negotiating contracts, and procuring additional materials.

Other items contributing to the increase include costs relating to the removal of certain liens filed on the property for goods and services provided under contracts with the former Contractor, and costs to repair equipment damage that resulted from poor storage and maintenance on the part of the former Contractor.

In July 2016, the Company requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the incremental capital costs for Carty starting from its in service date to the date that such amounts are approved in a subsequent regulatory proceeding. The Company has requested that the OPUC delay its review of this deferral request until all legal actions with respect to this matter, including PGE's actions against the Sureties, have been resolved.

Any amounts approved by the OPUC for recovery under the deferral filing would be recognized in earnings in the period of such approval, however there is no assurance that such recovery would be granted by the OPUC. The Company believes that costs incurred to date and capitalized in Electric utility plant, net, in the condensed consolidated balance sheet, were prudently incurred. There have been no settlement discussions with regulators related to such costs.

The Company is involved in several litigation proceedings concerning the termination of the Construction Agreement and the payment obligations of the Sureties.

PGE is seeking recovery of incremental construction costs and other damages pursuant to breach of contract claims against the Contractor and claims against the Sureties pursuant to the Performance Bond. The Sureties have denied liability in whole under the Performance Bond.

Various actions relating to this matter have been filed in the U.S. District Court for the District of Oregon (U.S. District Court), in the Ninth Circuit Court of Appeals (Ninth Circuit), and in an arbitration proceeding, including the following:

- A breach of contract claim dated March 23, 2016, Portland General Electric Company v. Liberty Mutual Insurance Company and Zurich American Insurance Company, U.S. District Court of the District of Oregon, brought by PGE against the Sureties in U.S. District Court asserting that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Contractor's breach of contract. The Company's complaint disputes the Sureties' assertion that the Company wrongfully terminated the Construction Agreement and asserts that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Sureties' breach of contract, including damages in excess of the

$145.6 million stated amount of the Performance Bond. Such damages include additional costs incurred by PGE to complete Carty.

- A claim dated October 21, 2016, Portland General Electric Company v. Abeinsa EPC LLC, Abener Construction Services, LLC (formerly known as Abener Engineering and Construction Services, LLC), Teyma Construction USA LLC, and Abeinsa Abener Teyma General Partnership, U.S. District Court of the District of Oregon, brought by PGE in U.S. District Court against the Contractor for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from the Contractor in excess of $200 million for: i) costs incurred to complete construction of Carty, settle claims with unpaid contractors and vendors, and remove liens; and ii) damages in excess of the construction costs, including a project management fee, liquidated damages under the Construction Agreement, legal fees and costs, damages due to delay of the project, warranty costs, and interest.
- A claim dated December 31, 2015, In the Matter of an Arbitration Under the Rules of the International Chamber of Commerce's Court of Arbitration, International Chamber of Commerce's Court of Arbitration, by Abengoa S.A. in the ICC arbitration proceeding alleging that the Company's termination of the Construction Agreement was wrongful and in breach of the terms of the agreement and did not give rise to any liability of Abengoa S.A.; and
- A claim by the Contractor against PGE in the ICC arbitration proceeding seeking damages of $117 million based on a claim that PGE wrongfully terminated the Construction Agreement and $44 million based on a claim that PGE failed to disclose certain information to the Contractor, in connection with the Contractor's bid submitted pursuant to the Company's request for proposals.

Following various procedural arguments in the ICC arbitration and the U.S. District Court, in July 2017, the Ninth Circuit held that the ICC arbitral tribunal had jurisdiction to determine what parties and what claims could be presented in the ICC arbitration as opposed to in court. A hearing before the ICC arbitral tribunal is expected to take place on April 9 and 10, 2018. The decision of the ICC arbitral tribunal is expected to determine the forum in which the above referenced claims will be heard.

After exhausting all remedies against the aforementioned parties, the Company intends to seek approval to recover any remaining excess amounts in customer prices in a subsequent regulatory proceeding. However, there is no assurance that such recovery would be allowed by the OPUC.

In accordance with GAAP and the Company's accounting policies, any such excess costs may be charged to expense at the time disallowance of recovery becomes probable and a reasonable estimate of the amount of such disallowance can be made. As of the date of this report, the Company has concluded that the likelihood is less than probable that a portion of the cost of Carty will be disallowed for recovery in customer prices. Accordingly, no loss has been recorded to date related to the project.

EPA Investigation of Portland Harbor

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

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

The EPA has finalized the feasibility study, along with the remedial investigation, and the results provided the framework for the EPA to determine a clean-up remedy for Portland Harbor that was documented in a Record of Decision (ROD) issued on January 6, 2017. The ROD outlines the EPA's selected remediation plan to clean-up for Portland Harbor, which has an estimated total cost of $1.7 billion, comprised of $1.2 billion related to remediation construction costs and $0.5 billion related to long-term operation and maintenance costs, for a combined discounted present value of $1.1 billion. Remediation construction costs are estimated to be incurred over a 13-year period, with long-term operation and maintenance costs estimated to be incurred over a 30-year period from the start of construction. The EPA acknowledges the estimated costs are based on data that is now outdated and that a period of pre-remedial design sampling is necessary to gather updated baseline data to better refine the remedial design and estimated cost. In December 2017, the EPA announced that four PRPs have entered into an administrative order on consent to conduct this additional sampling, which is estimated to be completed in two years. PGE is not among the four PRPs performing this sampling.

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

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

The NRD trustees may seek to negotiate legal settlements or take other legal actions against the parties responsible for the damages. Funds from such settlements must be used to restore injured resources and may also compensate the trustees for costs incurred in assessing the damages. The NRD trustees are in the process of negotiating NRDA liability with several PRPs, including PGE. The Company believes that PGE's portion of NRDA liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

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

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

Trojan Investment Recovery Class Actions

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

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

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

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

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

In June 2015, based on a motion filed by PGE, the Marion County Circuit Court (Circuit Court) lifted the abatement and in July 2015, the Circuit Court heard oral argument on the Company's motion for Summary Judgment. In March 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. On April 14, 2016, the plaintiffs appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon. Briefing on the appeal is now complete, with a Court of Appeals decision pending.

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

Deschutes River Alliance Clean Water Act Claims

On August 12, 2016, the Deschutes River Alliance (DRA) filed a lawsuit against the Company, Deschutes River Alliance v. Portland General Electric Company, U.S. District Court of the District of Oregon, which seeks injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. Specifically, DRA claims PGE has violated certain conditions contained in PGE's Water Quality Certification for the Pelton/Round Butte Hydroelectric Project (Project) related to dissolved oxygen, temperature, and measures of acidity or alkalinity of the water. DRA alleges the violations are related to PGE's operation of the Selective Water Withdrawal (SWW) facility at the Project.

The SWW, located above Round Butte Dam, is, among other things, designed to blend water from the surface of the reservoir with water near the bottom of the reservoir and was constructed and placed into service in 2010, as part of the FERC license requirements for the purpose of restoration and enhancement of native salmon and steelhead fisheries above the Project. DRA has alleged that PGE's operation of the SWW has caused the above-referenced violations of the CWA, which in turn have degraded the Deschutes River's fish and wildlife habitat below the Project and harmed the economic and personal interests of DRA's members and supporters.

In September 2016, PGE filed a motion to dismiss, which asserted that the CWA does not allow citizen suits of this nature, and that the FERC has jurisdiction over all licensing issues, including the alleged CWA violations. On March 27, 2017, the court denied PGE's motion to dismiss. On April 6, 2017, PGE filed a motion with the District Court for certification to file an interlocutory appeal with the Ninth Circuit and for a stay of the District Court proceeding. The District Court granted PGE's request on May 19, 2017, but the Ninth Circuit denied the appeal on August 14, 2017. On April 7, 2017, the District Court granted an unopposed motion filed by the Confederated Tribes of Warm Springs (the Tribes) to appear in the case as a friend of the court. The Tribes share ownership of the Project with PGE, but have not been named as a defendant.

Following conferences and negotiations involving various parties, and with the expiration of the stay, the District Court Judge, on January 17, 2018, established a briefing schedule for summary judgment motions.

The Company cannot predict the outcome of this matter, but believes that it has strong defenses to DRA's claims and intends to defend against them. Because i) this matter involves novel issues of law and ii) the mechanism and costs for achieving the relief sought in DRA's claims have not yet been determined, the Company cannot, at this time, determine the likelihood of whether the outcome of this matter will result in a material loss.

Other Matters

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

QUARTERLY FINANCIAL DATA
(Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2017				
Revenues, net	$ 530	$ 449	$ 515	$ 515
Income from operations	123	68	77	108
Net income	73	32	40	42
Earnings per share:*				
Basic	0.82	0.36	0.44	0.48
Diluted	0.82	0.36	0.44	0.48
2016				
Revenues, net	$ 487	$ 428	$ 484	$ 524
Income from operations	99	64	64	106
Net income	61	37	34	61
Earnings per share:*				
Basic	0.68	0.42	0.38	0.68
Diluted	0.68	0.42	0.38	0.68

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

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

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

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

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management's assessment was based on the framework established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2017, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2017, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report included in Item 8.—"Financial Statements and Supplementary Data," which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2017.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by Item 10 is incorporated herein by reference to the relevant information under the captions "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance," "Proposal 1: Election of Directors," and "Executive Officers" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 25, 2018.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions "Corporate Governance—Non-Employee Director Compensation," "Corporate Governance—Compensation Committee Interlocks and Insider Participation," "Compensation and Human Resources Committee Report," "Compensation Discussion and Analysis," and "Executive Compensation Tables" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 25, 2018.

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

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers" and "Equity Compensation Plans," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 25, 2018.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption "Corporate Governance" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 25, 2018.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions "Principal Accountant Fees and Services" and "Pre-Approval Policy for Independent Auditor Services" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 25, 2018.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

The financial statements are set forth under Item 8 of this Annual Report on Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Third Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 8-K filed May 9, 2014, Exhibit 3.1).
3.2*	Tenth Amended and Restated Bylaws of Portland General Electric Company (Form 8-K filed May 9, 2014, Exhibit 3.2).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965) (File No. 001-05532-99).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 001-05532-99).
4.3*	Sixty-second Supplemental Indenture dated April 1, 2009 (Form 8-K filed April 16, 2009, Exhibit 4.1) (File No. 001-05532-99).
4.4*	Seventy-third Supplemental Indenture dated August 1, 2017, between the Company and Wells Fargo Bank, National Association, as Trustee (Form 8-K filed August 3, 2017, Exhibit 4.1).
(10)	**Material Contracts**
10.1*	Amended and Restated Credit Agreement dated March 6, 2015 between Portland General Electric Company and Wells Fargo Bank, National Association, as Administrative Agent, Bank of America, N.A., Barclays Bank PLC, JPMorgan Chase Bank, N.A. and U.S. Bank National Association (Form 10-Q filed April 27, 2015, Exhibit 10.1).
10.2	First Amendment to Credit Agreement, dated February 21, 2017 among Portland General Electric Company, Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders.
10.3	Consent Agreement, dated November 3, 2017 among Portland General Electric Company, Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders.
10.4*	Portland General Electric Company Severance Pay Plan for Executive Employees, as amended and restated effective February 14, 2017. +
10.5*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2) (File No. 001-05532-99). +
10.6*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18) (File No. 001-05532-99). +
10.7*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1) (File No. 001-05532-99). +
10.8*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2) (File No. 001-05532-99). +
10.9*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.3) (File No. 001-05532-99). +
10.10*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4) (File No. 001-05532-99). +

Exhibit Number	Description
10.11*	Portland General Electric Company 2006 Stock Incentive Plan, as amended and restated effective March 31, 2016 (Form 10-Q filed July 28, 2017, Exhibit 10.1) (File No. 001-05532-99). +
10.12*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan (Form 8-K filed March 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.13*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.14*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers (Form 8-K filed February 26, 2008, Exhibit 10.1) (File No. 001-05532-99). +
10.15*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1) (File No. 001-05532-99). +
10.16*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters for Officers and Key Employees (Form 8-K filed February 19, 2010, Exhibit 10.1) (File No. 001-05532-99). +
10.17*	Form of Directors' Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.18*	Form of Officers' and Key Employees' Performance Stock Unit Agreement (Form 10-Q filed May 3, 2012, Exhibit 10.1) (File No. 001-05532-99). +
(12)	**Statements Re Computation of Ratios**
12.1	Computation of Ratio of Earnings to Fixed Charges.
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.
(101)	**Interactive Data File**
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Incorporated by reference as indicated.

\+ Indicates a management contract or compensatory plan or arrangement.

Certain instruments defining the rights of holders of other long-term debt of PGE are omitted pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K because the total amount of securities authorized under each such omitted instrument does not exceed 10% of the total consolidated assets of the Company and its subsidiaries. PGE hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Upon written request to Investor Relations, Portland General Electric Company, 121 S.W. Salmon Street, Portland, Oregon 97204, the Company will furnish shareholders with a copy of any Exhibit upon payment of reasonable fees for reproduction costs incurred in furnishing requested Exhibits.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 15, 2018.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ MARIA M. POPE

Maria M. Pope
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 15, 2018.

Signature	Title
/s/ MARIA M. POPE **Maria M. Pope**	*President, Chief Executive Officer, and Director* (principal executive officer)
/s/ JAMES F. LOBDELL **James F. Lobdell**	*Senior Vice President of Finance, Chief Financial Officer, and Treasurer* (principal financial and accounting officer)
/s/ JOHN W. BALLANTINE **John W. Ballantine**	*Director*
/s/ RODNEY L. BROWN, JR. **Rodney L. Brown, Jr.**	*Director*
/s/ JACK E. DAVIS **Jack E. Davis**	*Director*
/s/ DAVID A. DIETZLER **David A. Dietzler**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ KATHRYN J. JACKSON **Kathryn J. Jackson**	*Director*
/s/ NEIL J. NELSON **Neil J. Nelson**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*
/s/ CHARLES W. SHIVERY **Charles W. Shivery**	*Director*

EXHIBIT 12.1

PORTLAND GENERAL ELECTRIC COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in thousands)

	Years Ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
Income from continuing operations before income taxes	$ 273,085	$ 243,108	$ 216,818	$ 236,679	$ 125,758
Total fixed charges	137,124	132,654	135,956	128,515	118,189
Total earnings	$ 410,209	$ 375,762	$ 352,774	$ 365,194	$ 243,947
Fixed charges:					
Interest expense	$ 119,636	$ 111,539	$ 113,861	$ 96,068	$ 100,818
Capitalized interest	6,001	10,820	12,520	22,441	6,892
Interest on certain long-term power contracts	5,311	4,946	5,140	5,137	5,996
Estimated interest factor in rental expense	6,176	5,349	4,435	4,869	4,483
Total fixed charges	$ 137,124	$ 132,654	$ 135,956	$ 128,515	$ 118,189
Ratio of earnings to fixed charges	2.99	2.83	2.59	2.84	2.06

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-214580 on Form S-3 and Registration Statements Nos. 333-135726, 333-142694, and 333-158059 on Forms S-8 of our report dated February 15, 2018, relating to the consolidated financial statements of Portland General Electric Company and subsidiaries, and the effectiveness of Portland General Electric Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Portland General Electric Company for the year ended December 31, 2017.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 15, 2018

EXHIBIT 31.1

CERTIFICATION

I, Maria M. Pope, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 15, 2018

/s/ MARIA M. POPE

Maria M. Pope
President and
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, James F. Lobdell, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 15, 2018

/s/ JAMES F. LOBDELL

James F. Lobdell
Senior Vice President of Finance, Chief Financial Officer, and Treasurer

EXHIBIT 32.1

CERTIFICATIONS PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED
PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

We, Maria M. Pope, President and Chief Executive Officer, and James F. Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the "Company"), hereby certify that the Company's Annual Report on Form 10-K for the year ended December 31, 2017, as filed with the Securities and Exchange Commission on February 16, 2018 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

We further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ MARIA M. POPE
Maria M. Pope
President and
Chief Executive Officer

Date: February 15, 2018

/s/ JAMES F. LOBDELL
James F. Lobdell
Senior Vice President of Finance,
Chief Financial Officer and
Treasurer

Date: February 15, 2018

Corporate Information

BOARD OF DIRECTORS

Jack E. Davis

Chairman of the Board of Directors, Portland General Electric; Retired Chief Executive Officer, Arizona Public Service Company

Maria M. Pope

President and Chief Executive Officer, Portland General Electric

John W. Ballantine

Retired Executive Vice President and Chief Risk Management Officer, First Chicago NBD Corporation

Rodney L. Brown Jr.

Founding Partner, Cascadia Law Group PLLC

David A. Dietzler

Retired Pacific Northwest Partner in Charge of Audit Practice, KPMG LLP

Kirby A. Dyess

Principal, Austin Capital Management LLC

Mark B. Ganz

President and Chief Executive Officer, Cambia Health Solutions, Inc.

Kathryn J. Jackson

Director of Energy and Technology Consulting, KeySource, Inc.

Neil J. Nelson

President, Siltronic Corporation

M. Lee Pelton

President, Emerson College

Charles W. Shivery

Retired Chairman, President and Chief Executive Officer, Northeast Utilities

CORPORATE OFFICERS

Maria M. Pope

President and Chief Executive Officer

James F. Lobdell

Senior Vice President, Finance, Chief Financial Officer and Treasurer

William O. Nicholson

Senior Vice President, Customer Service, Transmission and Distribution

Larry N. Bekkedahl

Vice President, Transmission and Distribution

Carol A. Dillin

Vice President, Customer Strategies and Business Development

Bradley Y. Jenkins

Vice President, Generation and Power Operations

Lisa A. Kaner

Vice President, General Counsel and Corporate Compliance Officer

John T. Kochavatr

Vice President, Information Technology and Chief Information Officer

Anne F. Mersereau

Vice President, Human Resources, Diversity and Inclusion

W. David Robertson

Vice President, Public Policy

Kristin A. Stathis

Vice President, Customer Service Operations

INVESTOR INFORMATION

Corporate Headquarters

Portland General Electric Company
121 S.W. Salmon Street
Portland, OR 97204
503.464.8000
Investors.PortlandGeneral.com

Transfer Agent

American Stock
Transfer & Trust Company
59 Maiden Lane
Plaza Level
New York, NY 10038
866.621.2788

Independent Auditors

Deloitte & Touche LLP
3900 U.S. Bancorp Tower
111 S.W. Fifth Avenue
Portland, OR 97204
503.222.1341

Form 10-K

A copy of the company's 2017 Annual Report on Form 10-K will be furnished, without charge, upon written request made to:

Christopher Liddle
Director of Investor Relations and Treasury
121 S.W. Salmon Street
1WTC0506
Portland, OR 97204

You may also obtain a copy of the Form 10-K by calling Investor Relations at 503.464.8586 or by downloading a copy from *Investors.PortlandGeneral.com*.

Market Information

Portland General Electric Company common stock trades on the New York Stock Exchange under the ticker symbol POR.

To vote online visit: Investors.PortlandGeneral.com

2017 Highlights

PEOPLE

100 percent

For the fifth year in a row, we earned a perfect score on the Human Rights Campaign's Corporate Equality Index

45,000

Hours volunteered by employees and retirees in the communities we serve

75,000

Children received PGE-sponsored electrical safety training — that's more than 40 percent of all students served by PGE

$4.2 million

Donated by PGE, employees, retirees and PGE Foundation to local schools and nonprofits

PLANET

100 MWa
Amount of qualifying renewables acknowledged to be run in an RFP

20 percent
Customers enrolled in our No. 1 in the nation renewable energy program — with more than 178,000 customers, we're the only company ever to exceed 150,000

1.84 million
MWh of renewable energy sold through our Green Future℠ program

1.25 million+
Miles powered at our Electric Avenue charging stations since Oct. 2015, avoiding an estimated 515 metric tons of CO_2

470,000
Juvenile fish migrated downstream on the Deschutes River through our reintroduction effort

Our latest sustainability report is available at **PortlandGeneral.com/Sustainability**, with 2017 updates coming this summer.

PERFORMANCE

$2.29
Non-GAAP diluted earnings per share and $204 million net income[1]

Doubled
Dividend has doubled after 11 consecutive annual increases since going public in 2006

$514 million
System investments in reliability and resiliency to better serve our growing customer base

3,976 MW
New summer peak on Aug. 3, 2017, when it reached 105° at Portland International Airport

875,000
Customers served, including 10,300 additional residential customers and 1,500 additional business customers in 2017

No. 1
Dispatchable Standby Generation program in the country — 59 sites and 123 MW

1. When excluding the effects of the recent federal Tax Cuts and Jobs Act, or $2.10 per share and $187 million net income based on generally accepted accounting principles

COVER PHOTO

Steel Bridge in Portland, Ore.

INSIDE SHAREHOLDER LETTER (LEFT)

Maria Pope, PGE President and Chief Executive Officer

Restoration efforts after a January snow storm

INSIDE SHAREHOLDER LETTER (RIGHT)

Wind plant technician Joshua Kopczynski at our Biglow Canyon Wind Farm

Volunteers at the Tualatin Public Library during Spring Into Action

INSIDE 2017 HIGHLIGHTS (LEFT)

PGE supports equality in the Portland Pride Parade

Our Summer of Safety events teach kids how to use electricity safely and wisely

Employees at our Avery Regional Service Center rally support for our Employee Giving Campaign

Volunteers help clean the Oregon Holocaust Memorial

Our 2017 Advisory Committee on Diversity & Inclusion leadership team

INSIDE 2017 HIGHLIGHTS (RIGHT)

Employee Susan Hill helped prepare for our entry into the western Energy Imbalance Market

Declaring our intent to continue to ensure the U.S. remains a global leader in reducing carbon emissions