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

# FORM 10-Q

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

For the quarterly period ended June 30, 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: **001-5532-99**

# 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 SW Salmon Street**
**Portland, Oregon 97204**
**(503) 464-8000**
(Address of principal executive offices, including zip code, and registrant's telephone number, including area code)

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. [x] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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).
[x] Yes [ ] No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the 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 standard 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 [x] No

Number of shares of common stock outstanding as of July 17, 2017 is 89,062,560 shares.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2017

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## DEFINITIONS

The following abbreviations and acronyms are used throughout this document:

| Abbreviation or Acronym | Definition |
|---|---|
| **AFDC** | Allowance for funds used during construction |
| **AUT** | Annual Power Cost Update Tariff |
| **Boardman** | Boardman coal-fired generating plant |
| **Carty** | Carty natural gas-fired generating plant |
| **Colstrip** | Colstrip Units 3 and 4 coal-fired generating plant |
| **CWIP** | Construction work-in-progress |
| **EPA** | United States Environmental Protection Agency |
| **FERC** | Federal Energy Regulatory Commission |
| **FMBs** | First Mortgage Bonds |
| **GAAP** | Accounting principles generally accepted in the United States of America |
| **GRC** | General Rate Case |
| **IRP** | Integrated Resource Plan |
| **Moody’s** | Moody’s Investors Service |
| **MW** | Megawatts |
| **MWa** | Average megawatts |
| **MWh** | Megawatt hours |
| **NVPC** | Net Variable Power Costs |
| **OCEP** | Oregon Clean Electricity and Coal Transition Plan |
| **OPUC** | Public Utility Commission of Oregon |
| **PCAM** | Power Cost Adjustment Mechanism |
| **RPS** | Renewable Portfolio Standard |
| **S&P** | S&P Global Ratings |
| **SEC** | United States Securities and Exchange Commission |
| **Trojan** | Trojan nuclear power plant |

## PART I — FINANCIAL INFORMATION

### Item 1. Financial Statements.

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| **Revenues, net** | **$ 449** | **$ 428** | **$ 979** | **$ 915** |
| **Operating expenses:** | | | | |
| Purchased power and fuel | 118 | 126 | 259 | 275 |
| Generation, transmission and distribution | 81 | 64 | 162 | 130 |
| Administrative and other | 65 | 61 | 133 | 122 |
| Depreciation and amortization | 86 | 83 | 170 | 165 |
| Taxes other than income taxes | 31 | 30 | 64 | 60 |
| Total operating expenses | 381 | 364 | 788 | 752 |
| **Income from operations** | **68** | **64** | **191** | **163** |
| **Interest expense, net** | 30 | 27 | 60 | 54 |
| **Other income:** | | | | |
| Allowance for equity funds used during construction | 3 | 8 | 5 | 15 |
| Miscellaneous income, net | 1 | 1 | 2 | — |
| Other income, net | 4 | 9 | 7 | 15 |
| **Income before income tax expense** | **42** | **46** | **138** | **124** |
| Income tax expense | 10 | 9 | 33 | 26 |
| **Net income** | **$ 32** | **$ 37** | **$ 105** | **$ 98** |
| Other comprehensive income | 1 | — | — | — |
| **Comprehensive income** | $ 33 | $ 37 | $ 105 | $ 98 |
| | | | | |
| Weighted-average shares outstanding—basic and diluted (in thousands) | 89,063 | 88,902 | 89,033 | 88,867 |
| | | | | |
| Earnings per share—basic and diluted | $ 0.36 | $ 0.42 | $ 1.18 | $ 1.10 |
| | | | | |
| Dividends declared per common share | $ 0.34 | $ 0.32 | $ 0.66 | $ 0.62 |

*See accompanying notes to condensed consolidated financial statements.*

**PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES**
**CONDENSED CONSOLIDATED BALANCE SHEETS**
(Dollars in millions)
(Unaudited)

| | June 30, 2017 | December 31, 2016 |
|---|---|---|
| **ASSETS** | | |
| **Current assets:** | | |
| Cash and cash equivalents | $ 33 | $ 6 |
| Accounts receivable, net | 139 | 155 |
| Unbilled revenues | 68 | 107 |
| Inventories | 82 | 82 |
| Regulatory assets—current | 47 | 36 |
| Other current assets | 43 | 77 |
| **Total current assets** | **412** | **463** |
| Electric utility plant, net | 6,573 | 6,434 |
| Regulatory assets—noncurrent | 536 | 498 |
| Nuclear decommissioning trust | 41 | 41 |
| Non-qualified benefit plan trust | 36 | 34 |
| Other noncurrent assets | 55 | 57 |
| **Total assets** | **$ 7,653** | **$ 7,527** |

*See accompanying notes to condensed consolidated financial statements.*

**PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES**
**CONDENSED CONSOLIDATED BALANCE SHEETS, continued**
(Dollars in millions)
(Unaudited)

| | June 30, 2017 | December 31, 2016 |
|---|---|---|
| **LIABILITIES AND EQUITY** | | |
| **Current liabilities:** | | |
| Accounts payable | $ 90 | $ 129 |
| Liabilities from price risk management activities—current | 46 | 44 |
| Current portion of long-term debt | 150 | 150 |
| Accrued expenses and other current liabilities | 226 | 254 |
| **Total current liabilities** | **512** | **577** |
| Long-term debt, net of current portion | 2,200 | 2,200 |
| Regulatory liabilities—noncurrent | 989 | 958 |
| Deferred income taxes | 685 | 669 |
| Unfunded status of pension and postretirement plans | 286 | 281 |
| Liabilities from price risk management activities—noncurrent | 158 | 125 |
| Asset retirement obligations | 165 | 161 |
| Non-qualified benefit plan liabilities | 106 | 105 |
| Other noncurrent liabilities | 160 | 107 |
| **Total liabilities** | **5,261** | **5,183** |
| **Commitments and contingencies (see notes)** | | |
| **Equity:** | | |
| Portland General Electric Company shareholders' equity: | | |
| Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of June 30, 2017 and December 31, 2016 | — | — |
| Common stock, no par value, 160,000,000 shares authorized; 89,062,560 and 88,946,704 shares issued and outstanding as of June 30, 2017 and December 31, 2016, respectively | 1,203 | 1,201 |
| Accumulated other comprehensive loss | (7) | (7) |
| Retained earnings | 1,196 | 1,150 |
| **Total equity** | **2,392** | **2,344** |
| **Total liabilities and equity** | **$ 7,653** | **$ 7,527** |

*See accompanying notes to condensed consolidated financial statements.*

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

| | Six Months Ended June 30, | |
|---|---|---|
| | **2017** | **2016** |
| **Cash flows from operating activities:** | | |
| Net income | $ 105 | $ 98 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 170 | 165 |
| Deferred income taxes | 20 | 20 |
| Pension and other postretirement benefits | 13 | 14 |
| Allowance for equity funds used during construction | (5) | (15) |
| Decoupling mechanism deferrals, net of amortization | (15) | (3) |
| Other non-cash income and expenses, net | 16 | 12 |
| Changes in working capital: | | |
| Decrease in accounts receivable and unbilled revenues | 55 | 59 |
| Increase in inventories | — | (4) |
| Decrease in margin deposits, net | 7 | 18 |
| Decrease in accounts payable and accrued liabilities | (29) | (13) |
| Other working capital items, net | 11 | 6 |
| Other, net | (15) | (19) |
| **Net cash provided by operating activities** | **333** | **338** |
| **Cash flows from investing activities:** | | |
| Capital expenditures | (245) | (319) |
| Sales of Nuclear decommissioning trust securities | 11 | 11 |
| Purchases of Nuclear decommissioning trust securities | (9) | (11) |
| Other, net | (2) | — |
| **Net cash used in investing activities** | **(245)** | **(319)** |

*See accompanying notes to condensed consolidated financial statements.*

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

| | Six Months Ended June 30, | |
|---|---|---|
| | **2017** | **2016** |
| **Cash flows from financing activities:** | | |
| Proceeds from issuance of long-term debt | — | 265 |
| Payments on long-term debt | — | (133) |
| Change in short-term debt | — | (6) |
| Dividends paid | (57) | (53) |
| Other | (4) | (3) |
| **Net cash (used in) provided by financing activities** | **(61)** | **70** |
| **Increase in cash and cash equivalents** | **27** | **89** |
| **Cash and cash equivalents, beginning of period** | **6** | **4** |
| **Cash and cash equivalents, end of period** | **$ 33** | **$ 93** |
| | | |
| **Supplemental cash flow information is as follows:** | | |
| Cash paid for interest, net of amounts capitalized | $ 55 | $ 49 |
| Cash paid for income taxes | 13 | 7 |
| Non-cash investing and financing activities: | | |
| Assets obtained under capital lease | 55 | 57 |

*See accompanying notes to condensed consolidated financial statements.*

**PORTLAND GENERAL ELECTRIC COMPANY**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**
(Unaudited)

## NOTE 1: BASIS OF PRESENTATION

### Nature of Business

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 allocation, located entirely within the State of Oregon, encompasses 51 incorporated cities, of which Portland and Salem are the largest. As of June 30, 2017, PGE served approximately 872,000 retail customers with a service area population of approximately 1.9 million, comprising approximately 46% of the state's population.

### Condensed Consolidated Financial Statements

These condensed consolidated financial statements have been prepared pursuant to the rules and regulations of the United States Securities and Exchange Commission (SEC). Certain information and note disclosures normally included in financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP) have been condensed or omitted pursuant to such regulations, although PGE believes that the disclosures provided are adequate to make the interim information presented not misleading.

To conform with the 2017 presentation, PGE has reclassified Decoupling mechanism deferrals, net of amortization of $(3) million from Other non-cash income and expenses, net within the operating activities section and reclassified both Payments on capital leases of $2 million and Debt issuance costs of $1 million to Other within the financing activities section of the condensed consolidated statement of cash flows for the six months ended June 30, 2016.

The financial information included herein for the three and six months ended June 30, 2017 and 2016 is unaudited; however, such information reflects all adjustments, consisting of normal recurring adjustments, that are, in the opinion of management, necessary for a fair presentation of the condensed consolidated financial position, condensed consolidated income and comprehensive income, and condensed consolidated cash flows of the Company for these interim periods. The financial information as of December 31, 2016 is derived from the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2016, included in Item 8 of PGE's Annual Report on Form 10-K, filed with the SEC on February 17, 2017, which should be read in conjunction with such condensed consolidated financial statements.

### Comprehensive Income

PGE recorded a net $1 million gain in other comprehensive income for the three month period ended June 30, 2017 due to the combination of changes in compensation retirement benefit liability and amortization, net of taxes of an immaterial amount, and other miscellaneous adjustments. For the six month period ended June 30, 2017, no material change has occurred in other comprehensive income. The Company had no material components of other comprehensive income to report for the three and six month periods ended June 30, 2016.

### Use of Estimates

The preparation of condensed consolidated financial statements in accordance with 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 experienced by the Company could differ materially from those estimates.

Certain costs are estimated for the full year and allocated to interim periods based on estimates of operating time expired, benefit received, or activity associated with the interim period; accordingly, such costs may not be reflective of amounts to be recognized for a full year. Due to seasonal fluctuations in electricity sales, as well as the price of wholesale energy and natural gas, interim financial results do not necessarily represent those to be expected for the year.

**Recent Accounting Pronouncements**

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

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

In 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. The Company is in the process of evaluating the impact the guidance may have on its consolidated financial position and consolidated results of operations.

## NOTE 2: BALANCE SHEET COMPONENTS

### 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 inventory is recorded at the lower of average cost or net realizable value.

### Other Current Assets

Other current assets consist of the following (in millions):

| | June 30, 2017 | December 31, 2016 |
|---|---|---|
| Prepaid expenses | $ 34 | $ 48 |
| Margin deposits | 1 | 8 |
| Assets from price risk management activities | 5 | 18 |
| Other | 3 | 3 |
| Other current assets | $ 43 | $ 77 |

### Electric Utility Plant, Net

Electric utility plant, net consists of the following (in millions):

| | June 30, 2017 | December 31, 2016 |
|---|---|---|
| Electric utility plant | $ 9,674 | $ 9,534 |
| Construction work-in-progress | 346 | 213 |
| Total cost | 10,020 | 9,747 |
| Less: accumulated depreciation and amortization | (3,447) | (3,313) |
| Electric utility plant, net | $ 6,573 | $ 6,434 |

Accumulated depreciation and amortization in the table above includes accumulated amortization related to intangible assets of $277 million and $257 million as of June 30, 2017 and December 31, 2016, respectively. Amortization expense related to intangible assets was $12 million and $10 million for the three months ended June 30, 2017 and 2016, respectively, and $23 million and $22 million for the six months ended June 30, 2017 and 2016, respectively. The Company's intangible assets primarily consist of computer software development and hydro licensing costs.

PORTLAND GENERAL ELECTRIC COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued
(Unaudited)

**Regulatory Assets and Liabilities**

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

| | June 30, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| | Current | Noncurrent | Current | Noncurrent |
| Regulatory assets: | | | | |
| Price risk management | $ 41 | $ 156 | $ 26 | $ 120 |
| Pension and other postretirement plans | — | 229 | — | 235 |
| Deferred income taxes | — | 82 | — | 86 |
| Debt issuance costs | — | 20 | — | 22 |
| Other | 6 | 49 | 10 | 35 |
| Total regulatory assets | $ 47 | $ 536 | $ 36 | $ 498 |
| Regulatory liabilities: | | | | |
| Asset retirement removal costs | $ — | $ 910 | $ — | $ 887 |
| Trojan decommissioning activities | 8 | — | 18 | — |
| Asset retirement obligations | — | 51 | — | 49 |
| Other | 26 | 28 | 33 | 22 |
| Total regulatory liabilities | $ 34 * | $ 989 | $ 51 * | $ 958 |

* Included in Accrued expenses and other current liabilities in the condensed consolidated balance sheets.

**Accrued Expenses and Other Current Liabilities**

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

| | June 30, 2017 | December 31, 2016 |
|---|---|---|
| Regulatory liabilities—current | $ 34 | $ 51 |
| Accrued employee compensation and benefits | 52 | 52 |
| Accrued interest payable | 25 | 25 |
| Accrued dividends payable | 31 | 30 |
| Accrued taxes payable | 25 | 25 |
| Other | 59 | 71 |
| Total accrued expenses and other current liabilities | $ 226 | $ 254 |

**Credit Facilities**

As of June 30, 2017, PGE had a $500 million revolving credit facility scheduled to expire in November 2020.

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. During the first quarter of 2017, PGE exercised one of the two one-year extensions available under the terms of the credit facility. Such action resulted in an updated expiration date of November 2020. The facility also contains a provision that requires annual fees based on PGE's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65% of total capitalization. As of June 30, 2017, PGE was in compliance with this covenant with a 51.0% debt-to-total capital ratio.

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

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

Under the revolving credit facility, as of June 30, 2017, since PGE had no borrowings outstanding, and no commercial paper or letters of credit issued, 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 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 $56 million were outstanding as of June 30, 2017. Letters of credit issued are not reflected on the Company’s condensed consolidated balance sheets.

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

**Long-term Debt**

During the six months ended June 30, 2017, PGE did not enter into any First Mortgage Bond (FMB) long-term debt transactions.

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

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

The term loan interest rates are set at the beginning of the interest period for periods of one, three, or six months, as selected by PGE, and are based on the London Interbank Offered Rate plus 63 basis points, and was 1.8% as of June 30, 2017, with no other fees.

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

**PORTLAND GENERAL ELECTRIC COMPANY**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued**
(Unaudited)

**Defined Benefit Pension Plan Costs**

Components of net periodic benefit cost under the defined benefit pension plan are as follows (in millions):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Service cost | $ 4 | $ 4 | $ 8 | $ 8 |
| Interest cost | 9 | 8 | 17 | 16 |
| Expected return on plan assets | (10) | (10) | (20) | (20) |
| Amortization of net actuarial loss | 3 | 4 | 6 | 8 |
| Net periodic benefit cost | $ 6 | $ 6 | $ 11 | $ 12 |

**NOTE 3: 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 condensed consolidated balance sheets, for which it is practicable to estimate fair value as of June 30, 2017 and December 31, 2016, and then classifies these financial assets and liabilities based on a fair value hierarchy that is applied to prioritize the inputs to the valuation techniques used to measure fair value. The three levels of the fair value hierarchy 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 that 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; instead 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 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 three and six month periods ended June 30, 2017 and 2016, except those presented in this note.

**PORTLAND GENERAL ELECTRIC COMPANY**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued**
(Unaudited)

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 June 30, 2017 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Other[2] | Total |
| Assets: | | | | | |
| Nuclear decommissioning trust: [1] | | | | | |
| Debt securities: | | | | | |
| Domestic government | $ 2 | $ 8 | $ — | $ — | $ 10 |
| Corporate credit | — | 8 | — | — | 8 |
| Money market funds measured at NAV [2] | — | — | — | 23 | 23 |
| Non-qualified benefit plan trust: [3] | | | | | |
| Money market funds | 2 | — | — | — | 2 |
| Equity securities—domestic | 6 | — | — | — | 6 |
| Debt securities—domestic government | 1 | — | — | — | 1 |
| Collective trust—domestic equity measured at NAV [2] | — | — | — | — | — |
| Assets from price risk management activities: [1] [4] | | | | | |
| Electricity | — | 3 | 2 | — | 5 |
| Natural gas | — | 2 | — | — | 2 |
| | $ 11 | $ 21 | $ 2 | $ 23 | $ 57 |
| Liabilities from price risk management activities: [1] [4] | | | | | |
| Electricity | $ — | $ 2 | $ 144 | $ — | $ 146 |
| Natural gas | — | 47 | 11 | — | 58 |
| | $ — | $ 49 | $ 155 | $ — | $ 204 |

(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 $27 million, which are recorded at cash surrender value.
(4) For further information, see Note 4, Price Risk Management.

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| | 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 |
| Collective trust—domestic equity measured at NAV [2] | — | — | — | 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 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 4, Price Risk Management.

***Trust assets*** held in the Nuclear decommissioning and Non-qualified benefit plan (NQ Plan) trusts are recorded at fair value in PGE's condensed 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 yields 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.

*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.

*Common and collective trust funds*—PGE invests in common and collective trust funds that invest in equity securities. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value as a practical expedient. A majority of the funds provide for daily liquidity with appropriate written notice. One fund allows for withdrawal from all accounts as of the last day on each calendar month, with at least 10 days' prior written notice, and provides for a 95% payment to be made within 30 days, and the balance to be paid after the annual fund audit is complete. Common and collective trusts are not classified in the fair value hierarchy as they are valued at NAV as a practical expedient.

***Assets and liabilities from price risk management activities*** are recorded at fair value in PGE's condensed 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 net variable power costs (NVPC) for the Company's retail customers. For additional information regarding these assets and liabilities, see Note 4, 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.

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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:

| | Fair Value | | | | Price per Unit | | |
|---|---|---|---|---|---|---|---|
| **Commodity Contracts** | **Assets** | **Liabilities** | **Valuation Technique** | **Significant Unobservable Input** | **Low** | **High** | **Weighted Average** |
| | (in millions) | | | | | | |
| **As of June 30, 2017:** | | | | | | | |
| Electricity physical forwards | $ — | $ 143 | Discounted cash flow | Electricity forward price (per MWh) | $ 12.25 | $ 35.56 | $ 27.90 |
| Natural gas financial swaps | — | 11 | Discounted cash flow | Natural gas forward price (per Decatherm) | 1.70 | 3.15 | 2.14 |
| Electricity financial futures | 2 | 1 | Discounted cash flow | Electricity forward price (per MWh) | 15.83 | 29.94 | 24.37 |
| | $ 2 | $ 155 | | | | | |
| **As of December 31, 2016:** | | | | | | | |
| Electricity physical forwards | $ — | $ 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 Decatherm) | 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 PGE’s position as either the buyer or seller under 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) |

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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):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Balance as of the beginning of the period | 144 | 131 | $ 119 | $ 119 |
| Net realized and unrealized losses* | 9 | 28 | 35 | 40 |
| Transfers out of Level 3 to Level 2 | — | (1) | (1) | (1) |
| Balance as of the end of the period | $ 153 | $ 158 | $ 153 | $ 158 |

* Both realized and unrealized losses, of which the unrealized portion is fully offset by the effects of regulatory accounting until settlement of the underlying transactions, are recorded in Purchased power and fuel expense in the condensed consolidated statements of income.

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 three and six months ended June 30, 2017 and 2016, there were nominal transfers into Level 3 from Level 2. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its derivative instruments.

Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur, as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

***Long-term debt*** is recorded at amortized cost in PGE's condensed consolidated balance sheets. The fair value of the Company's FMBs and Pollution Control Revenue Bonds 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 a 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 June 30, 2017, the carrying amount of PGE's long-term debt was $2,350 million, net of $11 million of unamortized debt expense, and its estimated aggregate fair value was $2,748 million, consisting of $2,598 million and $150 million classified as Level 2 and Level 3, respectively, 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, and its estimated aggregate fair value was $2,693 million, consisting of $2,543 million and $150 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy.

## NOTE 4: 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 generation 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 flows.

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign currency rate risk in order to reduce volatility in NVPC for its retail customers. Such derivative instruments may include forward, futures, swaps, and option contracts, which are recorded at fair value on the condensed consolidated balance sheets, for electricity, natural gas, oil, and foreign currency, with changes in fair value recorded in the condensed consolidated statements of income. In accordance with the ratemaking and cost recovery processes authorized by the Public Utility Commission of Oregon (OPUC), the Company recognizes a regulatory asset or liability to defer the gains and losses from derivative instruments 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):

| | June 30, 2017 | December 31, 2016 |
|---|---|---|
| **Current assets:** | | |
| Commodity contracts: | | |
| Electricity | $ 3 | $ 6 |
| Natural gas | 2 | 12 |
| Total current derivative assets | 5 (1) | 18 (1) |
| **Noncurrent assets:** | | |
| Commodity contracts: | | |
| Electricity | 2 | 1 |
| Natural gas | — | 4 |
| Total noncurrent derivative assets | 2 (2) | 5 (2) |
| Total derivative assets not designated as hedging instruments | $ 7 | $ 23 |
| Total derivative assets | $ 7 | $ 23 |
| **Current liabilities:** | | |
| Commodity contracts: | | |
| Electricity | $ 10 | $ 12 |
| Natural gas | 36 | 32 |
| Total current derivative liabilities | 46 | 44 |
| **Noncurrent liabilities:** | | |
| Commodity contracts: | | |
| Electricity | 136 | 106 |
| Natural gas | 22 | 19 |
| Total noncurrent derivative liabilities | 158 | 125 |
| Total derivative liabilities not designated as hedging instruments | $ 204 | $ 169 |
| Total derivative liabilities | $ 204 | $ 169 |

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

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

| | June 30, 2017 | | | December 31, 2016 | | |
|---|---|---|---|---|---|---|
| Commodity contracts: | | | | | | |
| Electricity | | 5 | MWh | | 8 | MWh |
| Natural gas | | 118 | Decatherms | | 107 | Decatherms |
| Foreign currency | $ | 28 | Canadian | $ | 22 | Canadian |

PGE has elected to report gross on the condensed consolidated balance sheets the positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement. In the case of default on, or termination of, any contract under the master netting arrangements, these agreements provide for the net settlement of all related contractual obligations with a 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 June 30, 2017 and December 31, 2016, gross amounts included as Price risk management liabilities subject to master netting agreements were $147 million and $115 million, respectively, for which PGE posted collateral of $11 million as of June 30, 2017 and December 31, 2016, which consisted entirely of letters of credit. As of June 30, 2017, of the gross amounts recognized, $144 million was for electricity and $3 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 condensed consolidated statements of income and were as follows (in millions):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Commodity contracts: | | | | |
| Electricity | $ 16 | $ 27 | $ 49 | $ 52 |
| Natural Gas | 7 | (41) | 41 | (24) |
| Foreign currency exchange | (1) | — | (1) | (1) |

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the condensed consolidated statements of income by the effects of regulatory accounting. Of the net losses (gains) recognized in Net income for the three month periods ended June 30, 2017 and 2016, net losses of $4 million and net gains of $18 million have been offset, respectively. Net losses of $65 million and $16 million have been offset for the six month periods ended June 30, 2017 and 2016, respectively.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of June 30, 2017 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

| | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Commodity contracts: | | | | | | | |
| Electricity | $ 3 | $ 6 | $ 8 | $ 8 | $ 8 | $ 108 | $ 141 |
| Natural gas | 24 | 20 | 9 | 3 | — | — | 56 |
| Net unrealized loss | $ 27 | $ 26 | $ 17 | $ 11 | $ 8 | $ 108 | $ 197 |

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 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, 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 derivative instruments with credit-risk-related contingent features that were in a liability position as of June 30, 2017 was $202 million, for which PGE has posted $14 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at June 30, 2017, the cash requirement to either post as collateral or settle the instruments immediately would have been $200 million. Cash collateral for derivative instruments is classified as Margin deposits included in Other current assets on the Company's condensed consolidated balance sheet.

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

| | June 30, 2017 | December 31, 2016 |
|---|---|---|
| **Assets from price risk management activities:** | | |
| Counterparty A | 52% | 22% |
| Counterparty B | 6 | 17 |
| Counterparty C | 6 | 12 |
| | 64% | 51% |
| **Liabilities from price risk management activities:** | | |
| Counterparty D | 70% | 66% |
| | 70% | 66% |

See Note 3, Fair Value of Financial Instruments, for additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities.

## NOTE 5: EARNINGS PER SHARE

Basic earnings per share are computed based on the weighted average number of common shares outstanding during the period. 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 period using the treasury stock method. Potential common shares consist of: i) employee stock purchase plan shares; and ii) contingently issuable time-based and performance-based restricted stock units, along with associated dividend equivalent rights.

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Unvested performance-based restricted stock units and associated dividend equivalent rights are included in dilutive potential common shares only after the performance criteria have been met.

For the three and six month periods ended June 30, 2017, unvested performance-based restricted stock units and related dividend equivalent rights in the total amount of 273 thousand were excluded from the dilutive calculation because the performance goals had not been met, with 305 thousand excluded for the three and six month periods ended June 30, 2016.

Net income is the same for both the basic and diluted earnings per share computations. The denominators of the basic and diluted earnings per share computations are as follows (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Weighted-average common shares outstanding—basic and diluted | 89,063 | 88,902 | 89,033 | 88,867 |

## NOTE 6: EQUITY

The activity in equity during the six months ended June 30, 2017 and 2016 is as follows (dollars in millions):

| | Common Stock | | Accumulated Other Comprehensive Loss | Retained Earnings | Total |
|---|---|---|---|---|---|
| | Shares | Amount | | | |
| Balances as of December 31, 2016 | 88,946,704 | $ 1,201 | $ (7) | $ 1,150 | $ 2,344 |
| Issuances of shares pursuant to equity-based plans | 115,856 | 1 | — | — | 1 |
| Stock-based compensation | — | 1 | — | — | 1 |
| Dividends declared | — | — | — | (59) | (59) |
| Net income | — | — | — | 105 | 105 |
| Balances as of June 30, 2017 | 89,062,560 | $ 1,203 | $ (7) | $ 1,196 | $ 2,392 |
| | | | | | |
| Balances as of December 31, 2015 | 88,792,751 | $ 1,196 | $ (8) | $ 1,070 | $ 2,258 |
| Issuances of shares pursuant to equity-based plans | 128,005 | 1 | — | — | 1 |
| Stock-based compensation | — | 1 | — | — | 1 |
| Dividends declared | — | — | — | (55) | (55) |
| Net income | — | — | — | 98 | 98 |
| Balances as of June 30, 2016 | 88,920,756 | $ 1,198 | $ (8) | $ 1,113 | $ 2,303 |

## NOTE 7: 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 condensed 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 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.

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) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, will be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

**Carty**

*Background*—The Company is involved in several litigation proceedings that involve claims concerning the Company's termination of the construction agreement relating to the Carty natural gas-fired generating plant (Carty) located in Eastern Oregon, and the payment obligations of two sureties who provided a performance bond in connection with such agreement. The Company 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. There are currently lawsuits pending in U.S. District Court for the District of Oregon (U.S. District Court), as well as an arbitration proceeding before the International Chamber of Commerce International Court of Arbitration (ICC). In the most recent procedural development, on July 10, 2017, the Ninth Circuit Court of Appeals (Ninth Circuit) held that the ICC had jurisdiction to determine what parties and what claims could be presented in the ICC arbitration. PGE has filed a petition requesting en banc rehearing with the Ninth Circuit.

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

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

In January 2016, the Company received notice from the ICC that Abengoa S.A. had submitted a request for arbitration. In the request, Abengoa S.A. alleged that the Company's termination of the Construction Agreement was wrongful and in breach of the agreement terms and did not give rise to any liability of Abengoa S.A. under the terms of a guaranty in favor of PGE and pursuant to which Abengoa S.A. agreed to guaranty certain obligations of the Contractor under the Construction Agreement.

PGE disagreed with the assertions in the request for arbitration and in February 2016 filed a complaint and motion for preliminary injunction in the U.S. District Court seeking to have the arbitration claim dismissed on the grounds that the Company had not made a demand under the Abengoa S.A. guaranty, and therefore the matter was not ripe for arbitration. In addition, the Contractor has been joined as a party to the arbitration and is seeking damages of approximately $117 million based on a claim that PGE wrongfully terminated the Construction Agreement. The Contractor is also seeking estimated damages of $44 million based on a claim that PGE failed to disclose to the Contractor, in connection with the Contractor's bid submitted pursuant to the Company's request for proposals, certain information regarding union labor productivity rates in eastern Oregon, and that this alleged failure caused the Contractor to submit a bid with a contract price that was lower than the contract price that would have been submitted had Contractor known such information. PGE disagrees with both of these claims. A hearing on the jurisdictional issues before the ICC is scheduled for late October 2017.

*Bankruptcy Proceedings* - On March 28, 2016, Abengoa S.A. and several of its foreign affiliates filed petitions for recognition under Chapter 15 of the U.S. Bankruptcy Code requesting interim relief, including an injunction precluding the prosecution of any proceedings against the Chapter 15 debtors. On March 29, 2016, a number of Abengoa S.A.'s U.S. subsidiaries, including the four entities that collectively comprise the Contractor, filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. As a result, on April 5, 2016, the U.S. District Court issued an order stating that the Company's U.S. District Court action against Abengoa S.A., as further described below, was stayed. In early October 2016, the bankruptcy court in the Chapter 11 proceeding granted the Company's motion for relief from stay with respect to the four entities that collectively comprise the Contractor, which allowed the Company to bring claims against such entities in the U.S. District Court.

*U.S. District Court Proceedings against Sureties* - On March 9, 2016, the Sureties delivered a letter to the Company denying liability in whole under the Performance Bond. The Company disagreed with the Sureties' assertions and, on March 23, 2016, filed a breach of contract action against the Sureties in the U.S. District Court. The Company's complaint disputed the Sureties' assertion that the Company wrongfully terminated the Construction Agreement and asserts that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Sureties' breach of contract, including damages in excess of the $145.6 million stated amount of the Performance Bond. Such damages include additional costs incurred by PGE to complete Carty.

On April 15, 2016, the Sureties filed a motion to stay this U.S. District Court proceeding, alleging that PGE's claims should be addressed in the arbitration proceeding initiated by Abengoa S.A. and referenced above because PGE's claims are intertwined with the issues involved in such arbitration and all parties necessary to resolve PGE's claims are parties to the arbitration. PGE opposed the motion and filed a motion to prevent the Sureties from pursuing, in the ICC arbitration proceeding, claims relating to the Performance Bond. On July 27, 2016, the court denied the Sureties' motion to stay and granted PGE's motion for a preliminary injunction. The Sureties appealed the rulings to the Ninth Circuit. On July 10, 2017, the Ninth Circuit overturned the federal district court ruling and held that the ICC Arbitration panel has jurisdiction to determine what parties can be joined, and what claims can be presented, in the ICC Arbitration. On July 24, 2017, PGE filed a petition requesting en banc rehearing with the Ninth Circuit.

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*U.S. District Court Proceedings against Contractor* - On October 21, 2016, PGE filed a complaint in the U.S. District Court against Abeinsa for failure to satisfy its obligations under the Construction Agreement. PGE seeks damages from Abeinsa in excess of $200 million for: i) costs incurred to complete construction of Carty, settle claims with unpaid contractors and vendors and remove liens; and ii) damages in excess of the construction costs, including a project management fee, liquidated damages under the Construction Agreement, legal fees and costs, damages due to delay of the project, warranty costs, and interest. On March 21, 2017, the U.S. District Court entered an order staying the case. Unless the July 10, 2017 Ninth Circuit decision referenced in the preceding paragraph is reversed upon rehearing, the ICC Arbitration panel will determine whether these claims must be presented in the ICC Arbitration.

*Recovery of Excess Capital Costs*—Following termination of the Construction Agreement, PGE brought on new contractors and resumed construction. Carty was placed into service on July 29, 2016 and the Company began collecting its revenue requirement in customer prices on August 1, 2016, as authorized by the OPUC, based on the approved cost of $514 million. Actual costs for Carty have exceeded the amount approved for inclusion in customer prices by the OPUC and as of June 30, 2017, PGE has capitalized $635 million for Carty, classified as Electric utility plant. The incremental costs resulted from various matters relating to the resumption of construction activities following the termination of the Construction Agreement, including, among other things, determining the remaining scope of construction, preparing work plans for contractors, identifying new contractors, negotiating contracts, and procuring additional materials. Costs also increased as a result of PGE's discovery through the construction process of latent defects in work performed by the former Contractor and the corresponding labor and materials required to correct the work.

Other items contributing to the increase include costs relating to the removal of certain liens filed on the property for goods and services provided under contracts with the former Contractor, and costs to repair equipment damage that resulted from poor storage and maintenance on the part of the former Contractor. Actual costs for Carty recorded as Electric utility plant do not reflect any offsetting amounts that may be received from the Sureties pursuant to the Performance Bond. The amounts recorded also exclude approximately $7 million of lien claims filed for goods and services provided under contracts with the former Contractor that remain in dispute. The Company believes these liens are invalid and is contesting the claims in the courts.

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

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

**EPA Investigation of Portland Harbor**

A 1997 investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act 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 100.

The Portland Harbor site remedial investigation (RI) has been completed pursuant to an Administrative Order on Consent between the EPA and several PRPs known as the Lower Willamette Group (LWG), which does not include PGE. The LWG has funded the RI and feasibility study (FS) and has stated that it 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 FS, along with the RI, and these documents provided the framework for the EPA to determine a clean-up remedy for Portland Harbor that was documented in a Record of Decision (ROD) issued on January 6, 2017. The ROD outlines the EPA's selected remediation alternative to clean-up for Portland Harbor which has an estimated total cost of $1.7 billion, comprised of $1.2 billion related to remediation construction costs and $0.5 billion related to long-term operation and maintenance costs, for a combined discounted present value of $1.05 billion. As stated within the ROD, such cost ranges were estimated with accuracy between -30% and +50% of actual costs. 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. The EPA has prepared a Draft Sampling Plan to encourage PRPs to enter into an Administrative Order on Consent with the agency and begin the sampling process before the end of 2017. PGE is in the process of determining whether it will participate in such a process.

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

Where damage to natural resources has 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 damaged 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. PGE believes that the Company's portion of NRDA liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

As discussed above, significant uncertainties still remain concerning the precise boundaries for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, 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 in Marion County Circuit Court (Circuit Court) against PGE on behalf of two classes of electric service customers. The class action lawsuits seek damages totaling $260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment in Trojan.

In August 2006, the 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.

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

In 2008, the OPUC issued an order (2008 Order) that required PGE to provide refunds of $33 million, including interest, which refunds 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 Circuit Court lifted the abatement and in July 2015, the Circuit Court heard oral argument on the Company’s motion for Summary Judgment. Following oral argument on PGE’s motion for summary judgment, the plaintiffs moved to amend the complaints. On February 22, 2016, the Circuit Court denied the plaintiff’s motion to amend the complaint and on March 16, 2016, the Circuit Court entered a general judgment that granted the Company’s motion for summary judgment and dismissed all claims by the plaintiffs. On April 14, 2016, the plaintiffs appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon.

PGE believes that the October 2, 2014 OSC decision and the recent Circuit Court decisions have reduced the risk of a loss to the Company in excess of the amounts previously recorded and discussed above. However, because the class actions remain subject to a decision in the appeal, management believes that it is reasonably possible that such a loss in excess of amounts previously recorded 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 in the U.S. District Court of the District of Oregon. DRA’s claims seek 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.

On September 30, 2016, PGE filed a motion to dismiss, which asserted that the CWA does not allow citizen suits of this nature, and that 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. On April 7, 2017, the court granted an unopposed motion filed by the Confederated Tribes of Warm Springs (the Tribes) to appear in the case as Amicus Curiae (friend of the court). The Tribes share ownership of the Project with PGE, but have not been named as a defendant. The parties agreed to defer decision on the motion for stay pending a ruling by the District Court on PGE’s request to file the interlocutory appeal. The District Court granted PGE’s request on May 19, 2017, but the Ninth Circuit has not yet ruled on whether it will hear the appeal.

Subsequently, the parties have begun settlement discussions, and have agreed to a 90-day stay of the District Court proceeding.

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 that 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.

## NOTE 8: 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 June 30, 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 condensed consolidated balance sheets with respect to these indemnities.

## Item 2. 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 forward-looking statements are expressed in good faith and are believed 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 the expectations, beliefs, or projections contained in such forward-looking statements 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 the 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 7, Contingencies, in the Notes to the Condensed Consolidated Financial Statements;
- 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 that could affect PGE's power generating facilities, including forced outages, adverse hydro and wind conditions, and fuel supply disruptions, any of which may cause the Company to incur repair costs or purchase replacement power at increased costs;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, either of which could result in the Company's inability to recover project costs;
- volatility in wholesale power and natural gas prices, which could require PGE to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to power and natural gas purchase agreements;
- changes in the availability and price of wholesale power and fuels, including natural gas, coal, and oil, and the impact of such changes on the Company's power costs;
- capital market conditions, including availability of capital, volatility of interest rates, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, any of which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, and the repayments of maturing debt;
- future laws, regulations, and proceedings that could increase the Company's costs of operating its thermal generating plants, or affect the operations of such plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury, and other gas emissions;
- changes in, and compliance with, environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures;

- declines in the fair value of securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities or information technology systems, or result in the release of confidential customer, employee, or Company information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and the number of employees approaching retirement;
- new federal, state, and local laws that could have adverse effects on operating results;
- 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. This MD&A should be read in conjunction with the Company's condensed consolidated financial statements contained in this report, as well as the consolidated financial statements and disclosures in its Annual Report on Form 10-K for the year ended December 31, 2016, and other periodic and current reports filed with the SEC.

PGE is a vertically integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity, as well as the wholesale purchase and sale of electricity and natural gas in order to meet the needs of its retail customers. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to retail customers in its service territory.

In the fourth quarter of 2016, PGE submitted to the OPUC its 2016 Integrated Resource Plan (IRP) which addresses the Company's proposal to meet future customer demand and describes PGE's future energy supply strategy and anticipated resource needs over the next 20 years. The areas of focus for the plan, include, among other topics, additional resources needed to meet Oregon's Renewable Portfolio Standard (RPS) requirements and to replace energy from Boardman, the Company's coal-fired generating plant located in Eastern Oregon that will cease coal-fired operations at the end of 2020. For further information regarding the IRP, see *"Integrated Resource Plan"* in this Overview section of Item 2.

In February 2017, PGE filed a general rate case for a 2018 test year. Regulatory review is expected to occur throughout 2017, with new customer prices effective January 1, 2018. For further information, see *"General Rate Case"* in this Overview section of Item 2.

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

**Capital Requirements and Financing**—In total, the Company's 2017 capital expenditures are expected to approximate $550 million, excluding AFDC. For additional information regarding estimated capital expenditures, see "*Capital Requirements*" in the Liquidity and Capital Resources section of this Item 2.

PGE plans to fund the 2017 capital requirements and current maturities of long-term debt of $150 million with cash from operations during 2017, which is expected to range from $515 million to $565 million, and the issuance of debt securities of up to $300 million. For additional information, see *"Liquidity"* and *"Debt and Equity Financings"* in the Liquidity and Capital Resources section of this Item 2.

**General Rate Case**—On February 28, 2017, the Company filed with the OPUC a general rate case based on a 2018 test year (2018 GRC). The filing includes investments to ensure system safety and reliability and to better meet customers' changing needs and service expectations. The 2018 GRC requests a $100 million increase in the annual revenue requirement related primarily to an increase in base business costs for upgrades to PGE's transmission and distribution system, investments in strengthening and safeguarding the grid, and support for key initiatives such as participation in the Western Energy Imbalance Market (EIM).

The requested net increase in annual revenue requirement, representing an approximate 5.6% overall increase in customer prices, is based upon:

- A capital structure of 50% debt and 50% equity;
- A return on equity of 9.75%; and
- A rate base of $4.6 billion.

PGE, interveners, and the OPUC Staff have recently begun the settlement discussion phase of the public proceeding. Issues settled to date include depreciation expense, net variable power cost (NVPC), and a partial settlement on non-NVPC issues. The Company filed reply testimony on the remaining issues on July 18, 2017.
Regulatory review of the 2018 GRC will continue throughout 2017, with a final order targeted to be issued by the OPUC by December 2017 and new customer prices expected to become effective January 1, 2018.

The 2018 GRC filing (OPUC Docket UE 319), as well as copies of direct and reply testimony and exhibits, are available on the OPUC Internet website at www.oregon.gov/puc.

**Operating Activities—**The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues and income from operations to fluctuate from period to period. PGE typically experiences its highest average MWh deliveries and retail energy sales during the winter heating season, although deliveries also increase during the summer months, generally resulting from air conditioning demand. Retail customer price changes and customer usage patterns, which can be affected by the economy, also have an effect on revenues while wholesale power availability and price, hydro and wind generation, and fuel costs for thermal and gas plants can also affect income from operations.

*Customers and Demand*—The 4.6% increase in retail energy deliveries for the six months ended June 30, 2017 compared with the six months ended June 30, 2016 resulted from an increase in both residential and industrial energy deliveries, while commercial deliveries declined slightly.

Energy deliveries to residential customers increased 9.5% due in large part to the effects of cooler temperatures as well as residential customer growth of 1.3%. Energy deliveries to industrial customers increased 4.7%, largely due to continued strength in the high tech sector. Weather adjusted deliveries decreased 2.1% from the first half of 2016 reflecting the impact of lower residential use per customer partially offset by higher industrial deliveries. One additional day in the first half of 2016 due to leap year resulted in a comparative decrease of approximately 0.6% in retail energy deliveries. Energy efficiency and conservation efforts by retail customers also influence demand, although the financial effects of such efforts by residential and certain commercial customers are mitigated by the decoupling mechanism. See *“Legal, Regulatory and Environmental”* in this Overview section of Item 2 for further information on the decoupling mechanism.

During the second quarter of 2017, heating degree-days, an indication of the extent to which customers are likely to have used electricity for heating, were comparable to average and 70% above the second quarter of 2016. Residential energy deliveries, which are most weather sensitive, were higher in the second quarter of 2017 than the second quarter of 2016. Unseasonably warm weather in 2016, which decreased energy deliveries in that quarter, and temperatures that resulted in more heating and cooling degree days in the second quarter of 2017 contributed to the increased deliveries. See *“Revenues”* in the Results of Operations section of this Item 2 for further information on heating degree days.

The following table, which includes deliveries to the Company’s direct access customers who purchase their energy from Electricity Service Suppliers, presents the average number of retail customers by customer type, and the corresponding energy deliveries, for the periods indicated:

| | Six Months Ended June 30, | | | | |
|---|---|---|---|---|---|
| | 2017 | | 2016 | | |
| | Average Number of Customers | Retail Energy Deliveries* | Average Number of Customers | Retail Energy Deliveries* | % Increase (Decrease)in Energy Deliveries |
| Residential | 759,765 | 4,009 | 750,124 | 3,660 | 9.5 % |
| Commercial (PGE sales only) | 106,593 | 3,342 | 105,764 | 3,397 | (1.6)% |
| Direct Access | 458 | 303 | 315 | 262 | 15.6 % |
| Total Commercial | 107,051 | 3,645 | 106,079 | 3,659 | (0.4)% |
| Industrial (PGE sales only) | 198 | 1,435 | 189 | 1,414 | 1.5 % |
| Direct Access | 67 | 680 | 63 | 606 | 12.2 % |
| Total Industrial | 265 | 2,115 | 252 | 2,020 | 4.7 % |
| Total (PGE sales only) | 866,556 | 8,786 | 856,077 | 8,471 | 3.7 % |
| Total Direct Access | 525 | 983 | 378 | 868 | 13.2 % |
| Total | 867,081 | 9,769 | 856,455 | 9,339 | 4.6 % |

* In thousands of MWh.

The Company’s Retail Customer Choice Program caps participation by Direct Access customers in the fixed three-year and minimum five-year opt-out programs, which account for the majority of energy supplied to Direct Access customers. This cap would have limited energy deliveries to these customers to an amount equal to approximately 13% of PGE’s total retail energy deliveries for the first six months of 2017. Energy deliveries to Direct Access customers represented 9% of the Company’s total retail energy deliveries for the full year 2016, compared with 10% in the first six months of 2017.

*Power Operations*—To meet the energy needs of its retail customers, the Company utilizes a combination of its own generating resources and power purchases in the wholesale market. In an effort to obtain reasonably-priced power for its retail customers, PGE makes economic dispatch decisions based on numerous factors including plant availability, customer demand, river flows, wind conditions, and current wholesale prices.

PGE’s generating plants require varying levels of annual maintenance, during which the respective plants are unavailable to provide power. As a result, the amount of power generated to meet the Company’s retail load requirement can vary from period to period. Plant availability, which is affected by both planned and unplanned outages, approximated 87% and 93% during the six months ended June 30, 2017 and 2016, respectively, for those plants PGE operates. Plant availability of Colstrip Units 3 and 4, of which the Company has a 20% ownership interest, approximated 79% during both the six months ended June 30, 2017 and 2016, respectively.

During the six months ended June 30, 2017, the Company's generating plants provided approximately 49% of its retail load requirement compared with 54% in the six months ended June 30, 2016. The decrease in the proportion of power generated to meet the Company's retail load requirement was largely due to the combination of decreased production from the Company's wind facilities due to unfavorable weather conditions and a reduction in energy provided from the Company's thermal generation facilities due to outages and economic displacement. The decrease was partially offset by favorable hydro generation, during the first half of 2017. Favorable hydro conditions within the region had the effect of reducing energy prices in the wholesale power market which allowed the Company to economically displace a greater portion of its thermal generation to meet its retail load requirement.

Energy expected to be received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects is projected annually in the Annual Power Cost Update Tariff (AUT). Any excess in such hydro generation from that projected in the AUT normally displaces power from higher cost sources, while any shortfall is normally replaced with power from higher cost sources. For the six months ended June 30, 2017, energy received from these hydro resources increased by 16% compared to the six months ended June 30, 2016. Energy received from these hydro resources exceeded projected levels included in PGE's AUT by 14% and 1% for the six months ended June 30, 2017 and 2016, respectively, and provided 22% and 20% of the Company's retail load requirement for the six months ended June 30, 2017 and 2016, respectively. Energy from hydro resources is expected to exceed levels projected in the AUT for 2017.

Energy expected to be received from PGE-owned wind generating resources (Biglow Canyon and Tucannon River) is projected annually in the AUT. Any excess in wind generation from that projected in the AUT normally displaces power from higher cost sources, while any shortfall is normally replaced with power from higher cost sources. For the six months ended June 30, 2017, energy received from these wind generating resources decreased 19% compared to the six months ended June 30, 2016, resulting in the Company incurring higher replacement costs, as well as generating fewer Production Tax Credits (PTCs) than what was estimated in customer prices. Energy received from these wind generating resources fell short of that projected in PGE's AUT by 23% for the six months ended June 30, 2017 and 10% for the six months ended June 30, 2016, and provided approximately 9% and 11% of the Company's retail load requirement during the six months ended June 30, 2017 and 2016, respectively. Energy from wind resources is expected to be below projected levels included in the AUT for 2017.

Pursuant to the Company's power cost adjustment mechanism (PCAM), customer prices can be adjusted to reflect a portion of the difference between each year's forecasted net variable power costs (NVPC) included in customer prices (baseline NVPC) and actual NVPC for the year. 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 condensed consolidated statements of income) and is net of wholesale revenues, which are classified as Revenues, net in the condensed consolidated statements of income. Effective January 1, 2017, and pursuant to the Oregon Clean Electricity and Coal Transition Plan (OCEP), PGE's 2017 AUT filing included projected PTCs for the 2017 calendar year with actual variances subject to the PCAM. To the extent actual annual NVPC, subject to certain adjustments, is above or below the deadband, which is a defined range from $30 million above to $15 million below baseline NVPC, the PCAM provides for 90% of the variance beyond the deadband to be collected from or refunded to customers, respectively, subject to a regulated earnings test.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues, net in the Company's condensed consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense.

For the six months ended June 30, 2017, actual NVPC was $5 million below baseline NVPC. Based on forecast data, NVPC for the year ending December 31, 2017 is currently estimated to be below the baseline NVPC, but within the deadband range. Accordingly, no estimated collection from, or refund to, customers is expected under the PCAM for 2017.

For the six months ended June 30, 2016, actual NVPC was $6 million below baseline NVPC. For the year ended December 31, 2016, actual NVPC was $10 million below baseline NVPC, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded pursuant to PCAM for 2016.

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 13-mile pipeline, that will 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 $128 million. Due to the level of PGE's involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE has recorded $76 million to CWIP and a corresponding liability for the same amount to Other noncurrent liabilities in the condensed consolidated balance sheets as of June 30, 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 actual project costs for Carty have exceeded $514 million (as of June 30, 2017, PGE had $635 million in plant in service related to Carty) the Company will incur a higher cost of service than what is reflected in the current authorized revenue requirement amount. 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 $7 million for the six months ended June 30, 2017 and is estimated to be approximately $14 million for the full year 2017.

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 7, Contingencies, in the Notes to the Condensed Consolidated Financial Statements.

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

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

For additional information regarding the above and other matters, see Note 7, Contingencies, in the Notes to Condensed Consolidated Financial Statements.

*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 Oregon Clean Electricity and Coal Transition Plan (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 Oregon retail rates after 2030 (subject to an exception that extends this date until 2035 for the Company'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. In addition, PTCs were included in prices through the AUT filing for 2017.

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 has incorporated the effects of the legislation into its 2016 IRP, which is currently under consideration by the OPUC.

*Clean Power Plan*—In August 2015, the U.S. Environmental Protection Agency (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 establishes state-specific goals in terms of pounds of carbon dioxide emitted per MWh of energy produced. The rule is intended to result in a reduction of carbon emissions from existing power plants across all states to approximately 32% below 2005 levels by 2030.

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

PGE cannot predict how the states in which the Company's thermal generation facilities are located (Oregon and Montana) will implement the rule or how the rule may impact the Company's operations. The Company continues to monitor the developments around the implementation of the rule and efforts by state regulators to develop state plans. On February 9, 2016, the United States Supreme Court granted a stay, halting implementation and enforcement of the 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. Among other items, the Executive Order specifically directs the EPA to take several actions relating to the CPP. The EPA is instructed to review the final CPP and the final new source performance standard rules for new and modified power plants (NSPS) under the Clean Air Act and suspend, revise, or rescind the rules, if appropriate. Additionally, the Executive Order directs the EPA to notify the U.S. Attorney General of actions pursuant to this order so that courts that are judicially reviewing the above rules and associated litigation may stay or otherwise delay further the litigation while the EPA reviews them. In response to the Executive Order, the Department of Justice filed requests asking the U.S. Court of Appeals for the D.C. Circuit to suspend and hold in abeyance the current litigation over the CPP and the NSPS.

The Company cannot predict the impact of the stay, the ultimate outcome of the legal challenges, or whether Oregon and Montana will continue to develop implementation plans in light of the Supreme Court stay, the Executive Order, and consequential EPA actions.

*Recovery of Utility License Fees*—In May 2011, the city of Gresham, Oregon (Gresham), to which PGE provides service, 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.

On May 26, 2017, the OPUC Staff recommended against such recovery, stating that the OPUC has no legal authority to allow PGE to retroactively recover from customers in Gresham costs arising from the City’s privilege tax increase. PGE disputes the Staff’s position and believes that such amounts are legally eligible for recovery through customer prices. However, the Company cannot predict the outcome of this matter.

*Other Regulatory Matters*—The following discussion highlights certain regulatory items that have impacted the Company’s revenues, results of operations, or cash flows for the first two quarters of 2017 compared to the first two quarters of 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. Effective January 1, 2017, customer prices were decreased $56 million annually from 2016 levels to reflect an expected reduction in power costs under the AUT. As part of its 2018 GRC, PGE included a projected $29 million reduction in power costs that was included in the overall request submitted to the OPUC and expected to be reflected in customer prices effective January 1, 2018. Pursuant to the schedule established in the proceeding, updates of the forecast will occur through mid-November that could change this estimate.

Under the PCAM for 2016, NVPC was within the limits of the deadband, thus no potential refund or collection was recorded. The OPUC will review the results of the PCAM for 2016 during the latter half of 2017 with a decision expected in the fourth quarter 2017.

As a result of the recently passed 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, as well as providing the Company an opportunity to potentially collect or refund variances from projected PTC’s pursuant to the PCAM.

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

In March 2016, PGE submitted to the OPUC a RAC filing that requested no significant additions or deferrals for 2016. No RAC filing has been submitted in 2017.

*Decoupling*—The decoupling mechanism, which the OPUC has authorized through 2019, provides 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.

Accordingly, a refund of the $5 million recorded during 2014 occurred over a one-year period, which began January 1, 2016. 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, is expected to occur over a one-year period, which began January 1, 2017. The Company recorded an estimated collection of $3 million during the year ended December 31, 2016, which resulted from the 2016 GRC. Any collection for the year ended December 31, 2016 is expected to occur over a one-year period, which would begin January 1, 2018.

The Company recorded an estimated collection of $11 million during the six months ended June 30, 2017, which resulted from projections established in the 2016 GRC. Collections under the decoupling mechanism are subject to an annual limitation, which for 2017 would currently stand at approximately $18 million. Any collection from (or refund to) customers for the 2017 year is expected to occur over a one-year period, which would begin January 1, 2019.

*Storm Restoration Costs*—Beginning in 2011, the OPUC authorized the Company to collect $2 million annually from retail customers to establish a reserve balance to cover incremental expenses related to major storm damages, and to defer any amount not utilized in the current year. During 2015 and 2016, PGE fully utilized the existing reserve balance as a result of restoration costs associated with storm damage occurring during those years. In the first quarter of 2017, the Company incurred $5 million of incremental expenses as a result of a series of storm events and, as a result, the $2 million storm collection for 2017 was fully utilized. Consequently, PGE is exposed to the estimated incremental costs to-date, less the $2 million to be collected in 2017, as well as any additional major storm damage costs experienced during the remainder of 2017. A significant wind storm in early April 2017 resulted in additional incremental restoration expenses of approximately $6 million.

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 for 2017. Since the application will not likely be reviewed until 2017 is complete and all applicable costs are identified, and Company is unable to predict how the OPUC will ultimately rule on this application, the Company is unable to state with any certainty at this time whether these incremental costs are probable of recovery. Accordingly, no deferral has been recorded to-date. In the event it becomes probable that some or all of these costs are recoverable, the Company will record a deferral for such amounts at such time.

**Integrated Resource Plan**—PGE's IRP filing acknowledged by the OPUC in December 2014, and updated in December 2015, included an "Action Plan" that covered PGE's proposed actions before the end of 2017. In conjunction with the Action Plan, the Company announced plans to explore participation in the EIM, and has signed an agreement to join the EIM. Launched in 2014 by the California Independent System Operator, the EIM is a realtime energy wholesale market that automatically dispatches the lowest-cost electricity resources available to meet utility customer needs, while optimizing use of renewable energy over a large geographic area. The agreement outlines a schedule of activities and milestones in anticipation of the Company's participation in the EIM, targeted to begin in October 2017.

PGE filed a subsequent IRP (2016 IRP) with the OPUC in November 2016. The 2016 IRP addresses acquisition of additional resources to meet RPS requirements and replace energy and capacity from Boardman, which will cease coal-fired operations at the end of 2020. Further actions identified through 2021 are expected to offset expiring power purchase agreements and integrate variable energy resources, such as wind or solar generation facilities. The 2016 IRP also considers the OCEP, which, among other things, increased the RPS requirements for 2025 and future years. For further information on the OCEP, see the *"Legal, Regulatory and Environmental"* section in this Overview section of Item 2.

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

The 2016 IRP is available on PGE's website. The recommended Action Plan in the 2016 IRP encompasses both demand-side and supply-side actions as well as integration through flexible technologies. Specific initial recommendations included: i) the deployment of a minimum of 135 MWa of cost-effective energy efficiency; ii) the pursuit of up to 77 MW of additional demand response; and iii) the addition of approximately 175 MWa in RPS compliant renewable resources, which could include unbundled RECs. The initial submission also identified the need for PGE to acquire up to 850 MW of capacity, which included 375-550 MW of long-term dispatchable resources and up to 400 MW of annual capacity resources. As a result of incorporating actions since the initial IRP submission, as described in the following paragraphs, PGE has a remaining capacity need in the IRP for 2021 of 561 MW.

On March 29, 2017, PGE executed a 10-year Power Purchase Agreement (PPA), beginning September 1, 2018, with Douglas County Public Utility District for output from the Wells Hydroelectric Project (Wells), located in the state of Washington. The existing contract with Wells for 150 MW, set to expire in 2018, was identified as a portion of PGE's future resource needs in the initial 2016 IRP filing. Under the new PPA, PGE will continue to receive a portion of the capacity and energy produced at Wells, which is expected to reduce PGE's capacity need by 135 MW.

PGE has also incorporated its December 2016 load forecast update, which reduced its capacity need by 71 MW. In addition, contracts for approximately 143 MW of nameplate capacity were executed between June 1, 2016 and December 31, 2016, reducing PGE's capacity shortfall by 52 MW, with projects that include solar, biomass, and geothermal resources as required under the Public Utility Regulatory Policies Act of 1978 that defines such Qualifying Facilities.

PGE is engaged in productive bilateral negotiations with owners of existing regional resources to fill its remaining capacity need. Upon completion of detailed term sheets with potential sellers, the Company plans to file with the OPUC, by mid-August, a request to waive the guidelines that call for a competitive bidding process for resources greater than 100 MWs and a term of more than five years.

Since issuing the IRP, PGE has identified a potential benchmark wind resource that could have a nameplate capacity of up to approximately 500 MW, and which would qualify for the production tax credit. The Company continues to explore this option. The submission of this resource into a request for proposals (RFP) for renewable resources as a benchmark bid is subject to additional due diligence and the negotiation and execution of definitive agreements. If agreements are reached, the potential benchmark resource would be considered in the RFP process along with other renewable resource offerings. Such a resource would help PGE meet its RPS requirements, as well as provide a portion of the Company's identified capacity needs.

The renewal of existing hydro contracts, execution of the new contracts, and negotiation of bilateral agreements does not change the IRP Action Plan. Acknowledgment of the 2016 IRP is now expected in late summer 2017.

Following acknowledgment of the IRP, and the outcomes of the bilateral negotiations and waiver process, PGE may request approval from the OPUC to issue RFPs for any remaining capacity need. The Company has also proposed conducting an RFP for renewable resources as soon as possible after the commission issues an acknowledgement order. PGE is open to a variety of options and will seek the best combination of resources, consistent with the acknowledged IRP Action Plan, to meet its customers' future energy needs. Resource options could include hydro, wind, solar, geothermal, biomass, efficient natural gas-fired facilities, and energy storage. The RFP process will include oversight by an independent evaluator and review by the OPUC.

**Critical Accounting Policies**

PGE's critical accounting policies are outlined in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 17, 2017.

**Results of Operations**

The following table contains condensed consolidated statements of income information for the periods presented (dollars in millions):

| | Three Months Ended June 30, | | | | Six Months Ended June 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2017 | | 2016 | | 2017 | | 2016 | |
| **Revenues, net** | $ 449 | 100% | $ 428 | 100% | $ 979 | 100% | $ 915 | 100% |
| Purchased power and fuel | 118 | 26 | 126 | 29 | 259 | 26 | 275 | 30 |
| **Gross margin** | 331 | 74 | 302 | 71 | 720 | 74 | 640 | 70 |
| **Other operating expenses:** | | | | | | | | |
| Generation, transmission and distribution | 81 | 18 | 64 | 15 | 162 | 17 | 130 | 14 |
| Administrative and other | 65 | 15 | 61 | 14 | 133 | 14 | 122 | 13 |
| Depreciation and amortization | 86 | 19 | 83 | 19 | 170 | 17 | 165 | 18 |
| Taxes other than income taxes | 31 | 7 | 30 | 7 | 64 | 7 | 60 | 7 |
| Total other operating expenses | 263 | 59 | 238 | 56 | 529 | 54 | 477 | 52 |
| Income from operations | 68 | 15 | 64 | 15 | 191 | 20 | 163 | 18 |
| **Interest expense*** | 30 | 7 | 27 | 6 | 60 | 6 | 54 | 6 |
| **Other income:** | | | | | | | | |
| Allowance for equity funds used during construction | 3 | 1 | 8 | 2 | 5 | 1 | 15 | 2 |
| Miscellaneous income (expense), net | 1 | — | 1 | — | 2 | — | — | — |
| Other income, net | 4 | 1 | 9 | 2 | 7 | 1 | 15 | 2 |
| Income before income tax expense | 42 | 9 | 46 | 11 | 138 | 14 | 124 | 14 |
| **Income tax expense** | 10 | 2 | 9 | 2 | 33 | 3 | 26 | 3 |
| **Net income** | $ 32 | 7% | $ 37 | 9% | $ 105 | 11% | $ 98 | 11% |

* Net of an allowance for borrowed funds used during construction of $1 million and $4 million for the three months ended June 30, 2017 and 2016, respectively, and $3 million and $8 million for the six months ended June 30, 2017 and 2016.

**Net income** was $32 million, or $0.36 per diluted share, for the three months ended June 30, 2017 compared with $37 million, or $0.42 per diluted share, for the three months ended June 30, 2016. The decrease in Net income reflects the impact of the incremental storm costs during 2017 and lower PTCs that resulted from less wind generation in 2017 than 2016. Lower AFDC in 2017 reflects the completion of Carty in July 2016, and although recovery in customer prices began in August 2016, some earnings impact continues as costs exceeded those authorized by the OPUC. Operational costs (primarily depreciation, maintenance, and legal costs for Carty) continue to suppress earnings. Increased energy deliveries in 2017 and the corresponding improvement in gross margin were partially driven by weather changes. The timing of planned maintenance overhauls at the Company's generating facilities also contributed slightly to reduced earnings in 2017 when compared with the same period 2016.

**Net income** was $105 million, or $1.18 per diluted share, for the six months ended June 30, 2017, compared with $98 million, or $1.10 per diluted share, for the six months ended June 30, 2016. More seasonal temperatures contributed to higher energy demand in the first half of 2017 than 2016 and helped improve Gross margin. While total deliveries and customer growth remains favorable, weather adjusted usage per residential customer continues a pattern of long-term decline. As a result, the Company recorded an $11 million estimated collection under the Decoupling mechanism in the first half of 2017 compared with a $3 million collection recorded in the first half of 2016. Net income was aided by reduced NVPC as the average variable power cost per MWh declined 8%. NVPC was $5 million below baseline NVPC for the first six months of 2017, compared with $6 million below the baseline for the first six months of 2016. Allowance for equity funds used during construction decreased by $10 million in the first six months of 2017 in comparison with the first six months of 2016 due to lower average CWIP balances. Higher operating expenses, including additional depreciation expense, contributed to partially offset the higher net income.

**Three Months Ended June 30, 2017 Compared with the Three Months Ended June 30, 2016**

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

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| **Revenues* (dollars in millions):** | | | | |
| Retail: | | | | |
| Residential | $ 203 | 45% | $ 191 | 45% |
| Commercial | 162 | 36 | 162 | 38 |
| Industrial | 54 | 12 | 50 | 12 |
| Subtotal | 419 | 93 | 403 | 95 |
| Other retail revenues, net | 1 | — | 1 | — |
| Total retail revenues | 420 | 93 | 404 | 95 |
| Wholesale revenues | 16 | 4 | 14 | 3 |
| Other operating revenues | 13 | 3 | 10 | 2 |
| Total revenues | $ 449 | 100% | $ 428 | 100% |
| **Energy deliveries (MWh in thousands):** | | | | |
| Retail: | | | | |
| Residential | 1,626 | 31% | 1,557 | 30% |
| Commercial | 1,655 | 32 | 1,695 | 33 |
| Industrial | 749 | 14 | 717 | 14 |
| Subtotal | 4,030 | 77 | 3,969 | 76 |
| Direct access: | | | | |
| Commercial | 160 | 3 | 133 | 3 |
| Industrial | 359 | 7 | 323 | 6 |
| Subtotal | 519 | 10 | 456 | 9 |
| Total retail energy deliveries | 4,549 | 87 | 4,425 | 85 |
| Wholesale energy deliveries | 673 | 13 | 773 | 15 |
| Total energy deliveries | 5,222 | 100% | 5,198 | 100% |
| **Average number of retail customers:** | | | | |
| Residential | 761,443 | 88% | 750,961 | 88% |
| Commercial | 107,620 | 12 | 106,656 | 12 |
| Industrial | 196 | — | 190 | — |
| Direct access | 572 | — | 375 | — |
| Total | 869,831 | 100% | 858,182 | 100% |

* Includes revenues from customers who purchase their energy from the Company as well as $9 million and $7 million in revenues for 2017 and for 2016, respectively, from Direct Access customers for transmission and delivery charges only.

Total revenues for the three months ended June 30, 2017 increased $21 million compared to the three months ended June 30, 2016, as Total retail revenues increased $16 million while Other revenues were $3 million higher.

The change in Retail revenues resulted largely from the following:

- An $11 million increase resulting from 2.8% greater retail energy deliveries due to favorable weather conditions and an increase in deliveries to industrial customers, combined with an increase of $4 million that resulted from customer price changes. Energy deliveries to residential customers increased 4.4% in the second quarter of 2017 due in part to the effects of weather, as temperatures in 2016 were abnormally warm during the spring heating season, and continued customer growth. Energy deliveries to industrial customers increased 6.5%, largely due to strength in the high tech sector while energy deliveries to commercial customers declined 0.7%.
- A $1 million increase resulted from other tariffs, which included a $4 million increase in estimated collections under the decoupling mechanism, mostly offset by a variety of smaller items; partially offset by
- A $1 million decrease in Supplemental tariffs as a $4 million decrease due to the timing difference related to the Trojan spent fuel refund to customers, as the refund, offset in Depreciation and amortization, temporarily suspended in early 2016, has resumed, partially offset by an increase related to the accelerated cost recovery of Colstrip and various smaller tariffs.

Total cooling degree-days for the three months ended June 30, 2017, although below the level for the three months ended June 30, 2016, were nearly double the quarterly average. Total heating degree-days for the three months ended June 30, 2017 were 70% above the three months ended June 30, 2016 while nearly equivalent with historical averages.

The following table indicates the number of heating and cooling degree-days for the three months ended June 30, 2017 and 2016, along with 15-year averages based on weather data provided by the National Weather Service, as measured at Portland International Airport:

| | Heating Degree-days | | | Cooling Degree-days | | |
|---|---|---|---|---|---|---|
| | **2017** | **2016** | **Avg.** | **2017** | **2016** | **Avg.** |
| April | 421 | 227 | 386 | — | 18 | 1 |
| May | 196 | 109 | 216 | 41 | 31 | 18 |
| June | 69 | 67 | 87 | 88 | 105 | 51 |
| Totals for the quarter | 686 | 403 | 689 | 129 | 154 | 70 |

*Wholesale revenues* for the three months ended June 30, 2017 increased $2 million, or 14%, from the three months ended June 30, 2016, and consisted of a $3 million increase related to a 27% increase in average wholesale price partially offset by a $1 million decrease related to a 13% decrease in wholesale sales volume.

**Purchased power and fuel** expense decreased $8 million, or 6%, for the three months ended June 30, 2017 compared with the three months ended June 30, 2016. This change consisted of $2 million related to a decrease in the average variable power cost per MWh combined with $6 million related to a decrease in total system load.

The $2 million decrease in the average variable power cost was driven primarily by a $22 million decrease in purchased power due to a 21% decrease in the average variable power cost per MWh, partially offset by an $18 million increase in the average variable cost per MWh of energy generated from the Company’s natural gas-fired resources. These changes resulted in a decrease in the average variable power cost to $24.02 per MWh in the three months ended June 30, 2017 from $25.46 per MWh in the three months ended June 30, 2016

The $6 million decrease related to total system load was primarily comprised of a $22 million decrease quarter over quarter in energy generated from the Company’s natural gas-fired generation resources partially offset by a $17 million increase in energy obtained from purchased power.

The sources of energy for PGE’s total system load, as well as its retail load requirement, were as follows for the periods presented:

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | **2017** | | **2016** | |
| **Sources of energy (MWh in thousands):** | | | | |
| Generation: | | | | |
| Thermal: | | | | |
| Coal | 256 | 5% | 360 | 7% |
| Natural gas | 237 | 5 | 772 | 16 |
| Total thermal | 493 | 10 | 1,132 | 23 |
| Hydro | 528 | 11 | 379 | 7 |
| Wind | 504 | 10 | 628 | 13 |
| Total generation | 1,525 | 31 | 2,139 | 43 |
| Purchased power: | | | | |
| Term | 2,815 | 57 | 2,354 | 47 |
| Hydro | 503 | 10 | 393 | 8 |
| Wind | 85 | 2 | 91 | 2 |
| Total purchased power | 3,403 | 69 | 2,838 | 57 |
| Total system load | 4,928 | 100% | 4,977 | 100% |

| | | |
|---|---|---|
| Less: wholesale sales | (673) | (773) |
| Retail load requirement | 4,255 | 4,204 |

Energy received from PGE-owned wind generating resources decreased 20% in the three months ended June 30, 2017 compared with the same period of 2016 as a result of less favorable wind conditions. Energy received from these wind generating resources represented 12% and 15% of the Company's retail load requirements for the three months ended June 30, 2017 and 2016, respectively. Due to more favorable hydroelectric conditions, energy received from hydro resources increased during the three months ended June 30, 2017, from both PGE-owned generating plants and purchased from mid-Columbia projects, increased 34% compared with the same period of 2016, and represented 24% and 18% of the Company's retail load requirement for the three months ended June 30, 2017 and 2016, respectively.

The following table presents the actual April-to-September 2017 runoff (issued July 24, 2017), along with actual 2016, at particular points of major rivers relevant to PGE's hydro resources (as a percentage of normal, as measured over the 30-year period from 1981 through 2010):

| | Actual Runoff as a Percent of Normal* | |
|---|---|---|
| **Location** | **2017** | **2016** |
| Columbia River at The Dalles, Oregon | 124% | 89% |
| Mid-Columbia River at Grand Coulee, Washington | 115 | 91 |
| Clackamas River at Estacada, Oregon | 127 | 71 |
| Deschutes River at Moody, Oregon | 111 | 91 |

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

**Actual NVPC** for the three months ended June 30, 2017 decreased $10 million when compared with the three months ended June 30, 2016. The decrease was driven by a 6% decline in the average variable power cost per

MWh, and a 1% decrease in total system load. The increase in wholesale revenues was driven primarily by a 27% increase in the average wholesale sales price, offset slightly by a 13% decrease in wholesale sales volume. For the three months ended June 30, 2017, actual NVPC was $3 million below the baseline, while the three months ended June 30, 2016 actual NVPC was $7 million below baseline NVPC.

**Generation, transmission and distribution** expense increased $17 million, or 27%, in the three months ended June 30, 2017 compared with the three months ended June 30, 2016, driven primarily by $6 million of storm restoration costs, $5 million of operating expense for Carty (placed in service in July 2016), and $3 million higher maintenance expense at Beaver.

**Administrative and other** expense increased $4 million, or 7%, in the three months ended June 30, 2017 compared with the three months ended June 30, 2016. The increase was primarily due to a $1 million increase in legal costs related to Carty litigation and other miscellaneous expenses.

**Depreciation and amortization** expense increased $3 million in the three months ended June 30, 2017 compared with the three months ended June 30, 2016. The increase was driven by higher depreciation expense of $4 million due to Carty going into service in July 2016, $3 million higher depreciation expense for other capital additions, partially offset by an amortization credit in the second quarter of 2017 related to the Trojan spent fuel refund to customers, which is also reflected in reduced revenues. Increases or decreases in expense resulting from amortization of regulatory assets or liabilities are directly offset in revenues.

**Interest expense** increased $3 million, or 11% in the three months ended June 30, 2017 compared with the three months ended June 30, 2016, primarily due to a lower allowance for borrowed funds used during construction, as a result of Carty going into service in July 2016.

**Other income, net** decreased $5 million for the three months ended June 30, 2017 compared with the three months ended June 30, 2016, due to a decrease in the allowance for equity funds used during construction, primarily related to the construction of Carty in 2016.

**Income tax expense** was $10 million in the three months ended June 30, 2017 compared with $9 million in the three months ended June 30, 2016, with effective tax rates of 23.8% and 19.6%, respectively. The increase in income tax expense and effective tax rate was primarily due to lower production tax credits, partially offset by lower pre-tax income.

**Six Months Ended June 30, 2017 Compared with the Six Months Ended June 30, 2016**

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

| | Six Months Ended June 30, | | | | | |
|---|---|---|---|---|---|---|
| | 2017 | | | 2016 | | |
| **Revenues * (dollars in millions):** | | | | | | |
| Retail: | | | | | | |
| Residential | $ | 491 | 50% | $ | 445 | 49% |
| Commercial | | 323 | 33 | | 322 | 35 |
| Industrial | | 103 | 11 | | 99 | 11 |
| Subtotal | | 917 | 94 | | 866 | 95 |
| Other retail revenues, net | | 9 | 1 | | 4 | — |
| Total retail revenues | | 926 | 95 | | 870 | 95 |
| Wholesale revenues | | 29 | 3 | | 26 | 3 |
| Other operating revenues | | 24 | 2 | | 19 | 2 |
| Total revenues | $ | 979 | 100% | $ | 915 | 100% |
| **Energy deliveries (MWh in thousands):** | | | | | | |
| Retail: | | | | | | |
| Residential | | 4,009 | 37% | | 3,660 | 35% |
| Commercial | | 3,342 | 31 | | 3,397 | 32 |
| Industrial | | 1,435 | 13 | | 1,414 | 13 |
| Subtotal | | 8,786 | 81 | | 8,471 | 80 |
| Direct access: | | | | | | |
| Commercial | | 303 | 3 | | 262 | 2 |
| Industrial | | 680 | 6 | | 606 | 6 |
| Subtotal | | 983 | 9 | | 868 | 8 |
| Total retail energy deliveries | | 9,769 | 90 | | 9,339 | 88 |
| Wholesale energy deliveries | | 1,112 | 10 | | 1,261 | 12 |
| Total energy deliveries | | 10,881 | 100% | | 10,600 | 100% |
| **Average number of retail customers:** | | | | | | |
| Residential | | 759,765 | 88% | | 750,124 | 88% |
| Commercial | | 106,593 | 12 | | 105,764 | 12 |
| Industrial | | 198 | — | | 189 | — |
| Direct access | | 525 | — | | 378 | — |
| Total | | 867,081 | 100% | | 856,455 | 100% |

* Includes revenues from customers who purchase their energy from the Company as well as $18 million in revenues for 2017 and $15 million for 2016 from Direct Access customers for transmission and delivery charges only.

Total revenues for the six months ended June 30, 2017 increased $64 million, or 7%, compared to the six months ended June 30, 2016, consisting primarily of a $56 million increase in Total retail revenues.

The change in Retail revenues consisted of the following contributing factors:

- A $40 million increase due to a 4.6% increase in retail energy deliveries due largely to considerably cooler temperatures than experienced in the first half of 2016;

- A $14 million net increase from an average price increase of 1.6% over 2016 levels. Price changes, as authorized by the OPUC, include Carty going into service in mid-2016 and reflect a reduction as a result of lower NVPC as filed in the 2017 AUT. Higher delivery volumes also pushed average prices higher as the increased volumes are, at times, subject to higher tariff prices; and
- A $5 million increase resulted from other tariffs, which included a $7 million increase in estimated collections under the decoupling mechanism; partially offset by
- A $6 million decrease from supplemental tariffs, due in part to the $9 million timing difference related to the Trojan spent fuel refund to customers, as the refund, offset in Depreciation and amortization, temporarily suspended in early 2016, has resumed, partially offset by a $3 million increase related to the accelerated cost recovery of Colstrip.

Total heating degree-days for the six months ended June 30, 2017 were up 44% from those for the six months ended June 30, 2016 and 12% above average. Total cooling degree-days for the six months ended June 30, 2017 were 16% below those for the six months ended June 30, 2016, although 84% above average.

The following table indicates the number of heating and cooling degree-days for the six months ended June 30, 2017 and 2016, along with 15-year averages based on weather data provided by the National Weather Service, as measured at Portland International Airport:

| | **Heating Degree-days** | | | **Cooling Degree-days** | | |
|---|---|---|---|---|---|---|
| | **2017** | **2016** | **Avg.** | **2017** | **2016** | **Avg.** |
| First quarter | 2,171 | 1,585 | 1,867 | — | — | — |
| Second quarter | 686 | 403 | 689 | 129 | 154 | 70 |
| Year-to-date | 2,857 | 1,988 | 2,556 | 129 | 154 | 70 |

*Wholesale revenues* for the six months ended June 30, 2017 increased $3 million, or 12%, from the six months ended June 30, 2016, and consisted of $6 million related to a 26% increase in wholesale sales volume partially offset by $3 million related to a 12% decrease in wholesale prices.

*Other operating revenues* increased $5 million as the sale of gas not needed to fuel the Company’s generating facilities accounted for the majority of the increase.

**Purchased power and fuel** expense decreased $16 million, or 6%, for the six months ended June 30, 2017 compared with the six months ended June 30, 2016, and consisted of $23 million related to an 8% decrease in the average variable power cost per MWh, partially offset by $7 million related to a 2% increase in total system load.

The decrease in the average variable power cost to $24.65 per MWh in the six months ended June 30, 2017 from $26.84 per MWh in the six months ended June 30, 2016 was driven primarily by a $38 million, or 19% decrease in average variable power cost for purchased power, partially offset by a $16 million, or 9% increase in energy deliveries obtained from purchased power. The increase in energy obtained from purchased power is partially due to the replacement energy from a 19% reduction in energy deliveries from the Company’s wind generating resources due to unfavorable weather conditions. Average variable power costs for the Company’s coal-fired plants increased 18% resulting in a $5 million increase to power costs.

The sources of energy for PGE’s total system load, as well as its retail load requirement, were as follows for the periods presented:

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| **Sources of energy (MWh in thousands):** | | | | |
| Generation: | | | | |
| Thermal: | | | | |
| Coal | 1,167 | 11% | 1,117 | 11% |
| Natural gas | 1,540 | 15 | 1,774 | 17 |
| Total thermal | 2,707 | 26 | 2,891 | 28 |
| Hydro | 1,076 | 10 | 947 | 9 |
| Wind | 803 | 8 | 989 | 10 |
| Total generation | 4,586 | 44 | 4,827 | 47 |
| Purchased power: | | | | |
| Term | 4,797 | 46 | 4,442 | 43 |
| Hydro | 1,000 | 9 | 838 | 8 |
| Wind | 124 | 1 | 150 | 1 |
| Total purchased power | 5,921 | 56 | 5,430 | 53 |
| Total system load | 10,507 | 100% | 10,257 | 100% |
| Less: wholesale sales | (1,112) | | (1,261) | |
| Retail load requirement | 9,395 | | 8,996 | |

Energy received from PGE-owned wind generating resources decreased 19% in the six months ended June 30, 2017 compared with the same period of 2016 as a result of less favorable wind conditions. Energy received from these wind generating resources represented 9% and 11% of the Company’s retail load requirements for the six months ended June 30, 2017 and 2016, respectively. Due to more favorable hydroelectric conditions, energy received from hydro resources during the six months ended June 30, 2017, from both PGE-owned generating plants and purchased from mid-Columbia projects, increased 16% compared with the same period of 2016, and represented 22% and 20% of the Company’s retail load requirement for the six months ended June 30, 2017 and 2016, respectively.

**Actual NVPC** for the six months ended June 30, 2017 decreased $19 million when compared with the six months ended June 30, 2016. The decrease was driven by a 12% increase in wholesale revenues, an 8% decrease in the average variable power cost per MWh, partially offset by a 2% increase in total system load. The increase in wholesale revenues was driven primarily by a 26% increase in wholesale sales price, partially offset by a 12% decrease in sales volume. For the six months ended June 30, 2017 and 2016, actual NVPC was $5 million below and $6 million below baseline NVPC, respectively.

**Generation, transmission and distribution** expense increased $32 million, or 25%, in the six months ended June 30, 2017 compared with the six months ended June 30, 2016 driven primarily by $12 higher storm restoration costs, $11 million of operating expense for Carty (placed in service in July 2016), and $3 million higher maintenance expense at Beaver.

**Administrative and other** expense increased $11 million, or 9%, in the six months ended June 30, 2017 compared with the six months ended June 30, 2016. The increase was primarily due to $4 million higher employee incentives and $3 million higher legal costs for Carty.

**Depreciation and amortization** expense increased $5 million in the six months ended June 30, 2017 compared with the six months ended June 30, 2016. The increase was primarily driven by higher depreciation expense of $7 million due to the Carty plant going into service in July 2016, $8 million higher depreciation expense due to other capital additions, partially offset by a $10 million amortization credit in 2017 related to the Trojan spent fuel refund to customers, which is also reflected in reduced revenues.

**Taxes other than income taxes** increased $4 million, or 7%, in the six months ended June 30, 2017 compared to the six months ended June 30, 2016 due to $2 million higher property taxes, primarily due to the Carty plant going into service in July 2016.

**Interest expense** increased $6 million, or 11%, in the six months ended June 30, 2017 compared with the six months ended June 30, 2016, primarily due to a lower allowance for borrowed funds used during construction, as a result of Carty going into service in July 2016.

**Other income, net** was $7 million in the six months ended June 30, 2017 compared with $15 million in the six months ended June 30, 2016. The change was due to a $10 million decrease in the allowance for equity funds used during construction, primarily related to the Carty project, partially offset by higher gains on the non-qualified benefit trust assets.

**Income tax expense** was $33 million in the six months ended June 30, 2017 compared with $26 million in the six months ended June 30, 2016, with effective tax rates of 23.9% and 21.0%, respectively. The increase in income tax expense was driven by higher pre-tax income and a decrease in production tax credits.

**Liquidity and Capital Resources**

Capital Requirements

The following table presents PGE's estimated capital expenditures and contractual maturities of long-term debt for 2017 through 2021 (in millions, excluding AFDC):

| | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Ongoing capital expenditures (1) | $ 503 | $ 438 | $ 297 | $ 300 | $ 290 |
| Customer information system (2) | 47 | 15 | — | — | — |
| Total capital expenditures | $ 550 (3) | $ 453 | $ 297 | $ 300 | $ 290 |
| 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 connections. For 2017, amount shown includes $134 million for transmission, distribution, and generation resiliency projects.
(2) As of December 31, 2016 total capital expenditures for the Customer information project was $65 million, excluding AFDC.
(3) Includes preliminary engineering and removal costs, which are included in other net operating activities in the condensed 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 2.

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, as well as debt refinancing activities. PGE's liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposit requirements related to wholesale market activities, which can vary depending upon the Company's forward positions and the corresponding price curves.

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

| | Six Months Ended June 30, | |
|---|---|---|
| | 2017 | 2016 |
| Cash and cash equivalents, beginning of period | $ 6 | $ 4 |
| Net cash provided by (used in): | | |
| Operating activities | 333 | 338 |
| Investing activities | (245) | (319) |
| Financing activities | (61) | 70 |
| Increase in cash and cash equivalents | 27 | 89 |
| Cash and cash equivalents, end of period | $ 33 | $ 93 |

**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, with adjustments for certain non-cash items, such as depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. Net cash flows from operating activities for the six months ended June 30, 2017 decreased $5 million when compared with the six months ended June 30, 2016. Included in the change were a number of relatively small, somewhat offsetting, factors such as:

- A $16 million reduction in the comparative quarter over quarter decrease in Accounts payable and accrued liabilities; and
- An $11 million decrease in margin deposits; partially offset by
- A $13 million increase from the combination of higher Net income, increases in non-cash expenses for Depreciation and amortization, and a decrease in the non-cash credit to income for the Allowance for equity funds used during construction as Carty was placed in service in July 2016, net of the overall decrease resulting from Decoupling deferrals, and Other non-cash income and expenses; and
- A $9 million net increase from a combination of smaller net increases in Other working capital items, net and Other, net adjustments to net income.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. PGE estimates that such charges in 2017 will range from $340 million to $350 million. Combined with other sources, total cash expected to be provided by operations is estimated to range from $515 million to $565 million.

**Cash Flows from Investing Activities—**Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE’s generation facilities and transmission and distribution systems. Net cash used in investing activities for the six months ended June 30, 2017 decreased $74 million when compared with the six months ended June 30, 2016, largely due to the lower level of capital expenditures resulting from the completion of Carty during 2016.

The Company plans to make capital expenditures of approximately $550 million, excluding AFDC, in 2017, which it expects to fund with cash to be generated from operations during 2017, as discussed above, as well as with proceeds received from the issuances of debt securities. For additional information, see *“Debt and Equity Financings”* in this Liquidity and Capital Resources section of Item 2.

**Cash Flows from Financing Activities—**Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During the six months ended June 30, 2017, net cash was used in financing activities primarily for the payment of dividends of $57 million. During the six months ended June 30, 2016, net cash provided by financing activities consisted primarily of $265 million received from the issuances of

FMBs and borrowing under an unsecured credit agreement, partially offset by repayment of long-term debt of $133 million and the payment of dividends of $53 million.

Dividends on Common Stock

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, which may include, among other things, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

Common stock dividends declared during 2017 consist of the following:

| Declaration Date | Record Date | Payment Date | Dividends 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 |

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 its revolving credit facility, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient cash flow and liquidity to meet the Company's anticipated capital and operating requirements for the foreseeable future. However, the Company's ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions.

For 2017, PGE expects to fund estimated capital expenditures and maturities of long-term debt with cash from operations (which is expected to range from $515 million to $565 million), issuances of debt securities of up to $300 million, and the issuance of commercial paper, as needed. The actual timing and amount of any such issuances of debt and commercial paper will be dependent upon the timing and amount of capital expenditures and maturities of long-term debt.

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

As of June 30, 2017, PGE had a $500 million revolving credit facility scheduled to expire in November 2020. 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.

Under the revolving credit facility, as of June 30, 2017, PGE had no borrowings outstanding, and no commercial paper outstanding or letters of credit issued. As a result, as of June 30, 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 $56 million were outstanding as of June 30, 2017.

*Long-term Debt.* During the six months ended June 30, 2017, PGE had no long-term debt transactions. As of June 30, 2017, total long-term debt outstanding, net of $11 million of unamortized debt expense, was $2,350 million, with $150 million scheduled maturities classified as current.

The Company expects to execute a bond purchase agreement on August 2, 2017 under which it will issue First Mortgage Bonds in the amount of $225 million at an interest rate of 3.98%. The borrowing will consist of $75 million to be drawn in August with a maturity in 2048 and $150 million to be drawn in November 2017 with a maturity in 2047.

*Capital Structure.* PGE's financial objectives include maintaining a common equity ratio (common equity to total consolidated capitalization, including any current debt maturities) of approximately 50% over time. Achievement of this objective helps the Company maintain investment grade credit ratings and facilitates access to long-term capital at favorable interest rates. The Company's common equity ratio was 50.4% and 49.4% as of June 30, 2017 and December 31, 2016, respectively.

Credit Ratings and Debt Covenants

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

| | **Moody's** | **S&P** |
|---|---|---|
| First Mortgage Bonds | A1 | A- |
| Issuer rating | A3 | BBB |
| Commercial paper | Prime-2 | A-2 |
| Outlook | Stable | Stable |

Should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt below investment grade, the Company could be subject to requests by certain of its wholesale, commodity, and transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. The performance assurance collateral can be in the form of cash deposits or letters of credit, depending on the terms of the underlying agreements, 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, which is included in Other current assets on PGE's condensed consolidated balance sheets, while any letters of credit issued are not reflected on the Company's condensed consolidated balance sheets.

As of June 30, 2017, PGE had posted $21 million of collateral with these counterparties, consisting of $1 million in cash and $20 million in letters of credit. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of June 30, 2017, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade was approximately $77 million, and decreases to $27 million by December 31, 2017 and to $8 million by December 31, 2018. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade was approximately $164 million at June 30, 2017, and decreases to approximately $111 million by December 31, 2017 and to $85 million by December 31, 2018.

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

The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust (Indenture) securing the bonds. PGE estimates that on June 30, 2017, under the most restrictive issuance test in the Indenture, the Company could have issued up to approximately $1,217 million of additional FMBs. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges, or other dispositions of property.

PGE's credit facility contains customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65.0% of total capitalization (debt-to-total capital ratio). As of June 30, 2017, the Company's debt-to-total capital ratio, as calculated under the credit agreement, was 51.0%.

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.

Contractual Obligations

PGE's contractual obligations for 2017 and beyond are set forth in Part II, Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 17, 2017. For such obligations, there have been no material changes outside the ordinary course of business, as of June 30, 2017, except for the First Mortgage Bond long-term debt issuance discussed in the *"Debt and Equity Financings"* section in this Item 2.

## Item 3. 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. There have been no material changes to market risks affecting the Company from those set forth in Part II, Item 7A of the Company's Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 17, 2017.

## Item 4. Controls and Procedures.

*Disclosure Controls and Procedures*

PGE's management, under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures as required by Exchange Act Rule 13a-15(b) as of the end of the period covered by this report. Based on that evaluation, PGE's Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2017, these disclosure controls and procedures were effective.

*Changes in Internal Control over Financial Reporting*

There were no changes in PGE’s internal control over financial reporting that occurred during the period covered by this quarterly report that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

## PART II - OTHER INFORMATION

### Item 1. Legal Proceedings.

For further information regarding PGE’s legal proceedings, see “*Legal Proceedings*” set forth in Part I, Item 3 of the Company’s Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 17, 2017 and Part II, Item 1 of the Company’s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2017 filed with the SEC on April 28, 2017.

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

On July 27, 2016, the judge denied the Sureties’ motion to stay the case in favor of a pending ICC Arbitration and granted PGE’s motion for an injunction prohibiting the Sureties from pursuing any Performance Bond claims in the ICC Arbitration. The Sureties appealed the rulings to the Ninth Circuit and asked the U.S. District Court to stay the proceedings pending resolution of the appeal. On July 10, 2017, the Ninth Circuit overturned the U.S. District Court ruling and held that the ICC Arbitration panel has jurisdiction to determine what parties can be joined, and what claims can be presented, in the ICC Arbitration. On July 24, 2017, PGE filed a petition requesting en banc rehearing with the Ninth Circuit. For additional information on this matter, see Note 7, Contingencies, in the Notes to the Condensed Consolidated Financial Statements.

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

On October 21, 2016, PGE filed a complaint in the U.S. District Court against Abeinsa for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from Abeinsa in excess of $200 million for: i) costs incurred to complete construction of Carty, settle claims with unpaid contractors and vendors and remove liens; and ii) damages in excess of the construction costs, including a project management fee, liquidated damages under the Construction Agreement, legal fees and costs, damages due to delay of the project, warranty costs, and interest. On March 21, 2017, the judge entered an order staying the case. Unless the July 10, 2017 Ninth Circuit decision referenced in the preceding matter is reversed upon rehearing, the ICC Arbitration panel will determine whether these claims must be presented in the ICC Arbitration.

**Deschutes River Alliance v. Portland General Electric Company, U.S. District Court of the District of Oregon.**

On August 12, 2016, the Deschutes River Alliance (DRA) filed a lawsuit against the Company in U.S. District Court. DRA’s claims seek injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. The court denied PGE’s motion to dismiss and PGE then submitted a request on April 6, 2017, for interlocutory appeal to the Ninth Circuit of the order dismissing its motion to dismiss. The request also included a motion for stay of the lower court proceeding. The parties agreed to defer decision on the motion for stay pending a ruling on PGE’s request to file the interlocutory appeal. On May 19, 2017, the District Court granted PGE’s request to file the interlocutory appeal, but the Ninth Circuit has not yet ruled on w hether it will hear the appeal. Subsequently, the parties have begun settlement discussions, and have agreed to a stay until August 17, 2017 of the trial court proceeding. For additional information on this matter, see Note 7, Contingencies, in the Notes to the Condensed Consolidated Financial Statements.

## Item 1A. Risk Factors.

There have been no material changes to PGE's risk factors set forth in Part I, Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 17, 2017.

## Item 6. Exhibits.

| Exhibit Number | Description |
|---|---|
| 3.1 | Third Amended and Restated Articles of Incorporation of Portland General Electric Company (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed May 9, 2014). |
| 3.2 | Tenth Amended and Restated Bylaws of Portland General Electric Company (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed May 9, 2014). |
| 10.1 | Portland General Electric Company 2006 Stock Incentive Plan, as amended and restated March 31, 2016, filed herewith. |
| 31.1 | Certification of Chief Executive Officer. |
| 31.2 | Certification of Chief Financial Officer. |
| 32 | Certifications of Chief Executive Officer and Chief Financial Officer. |
| 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. |

Certain instruments defining the rights of holders of other long-term debt of the Company 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. The Company hereby agrees to furnish a copy of any such instrument to the SEC upon request.

## SIGNATURE

Pursuant to the requirements 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.

PORTLAND GENERAL ELECTRIC COMPANY
(Registrant)

Date: July 27, 2017

By: /s/ James F. Lobdell

James F. Lobdell
*Senior Vice President of Finance,*
*Chief Financial Officer and Treasurer*
(duly authorized officer and principal financial officer)

**PORTLAND GENERAL ELECTRIC COMPANY**

**2006 STOCK INCENTIVE PLAN**

**Effective as of March 31, 2006**

**(As Amended and Restated March 31, 2016)**

**1. Purpose.** The Portland General Electric Company 2006 Stock Incentive Plan, as amended and restated (the "Plan") is intended to provide incentives which will attract, retain and motivate highly competent persons as officers, directors and key employees of Portland General Electric Company (the "Company") and its subsidiaries and Affiliates, by providing them with appropriate incentives and rewards in the form of rights to earn shares of the common stock of the Company ("Common Stock") and cash equivalents.

**2. Definitions.** A listing of the defined terms utilized in the Plan is set forth in Appendix A.

**3. Effective Date of Plan.** The Plan is effective on March 31, 2006.

**4. Administration.**

(a) *Committee*. The Plan will be administered by a committee (the "Committee") appointed by the Board of Directors of the Company (the "Board of Directors") from among its members (which may be the Compensation and Human Resources Committee) and shall be comprised, solely of not less than two (2) members who shall be (i) "non-employee directors" within the meaning of Rule 16b-3(b)(3) (or any successor rule) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") and (ii) "outside directors" within the meaning of Treasury Regulation Section 1.162-27(e)(3) under Section 162(m) of the Internal Revenue Code of 1986, as amended (the "Code"). In addition, the Board of Directors may direct that, for the purpose of establishing the terms and conditions applicable to Awards granted to the Chief Executive Officer under the Plan, and determining amounts payable under such Awards, the Committee shall be comprised of each non-employee director who satisfies the standards of the New York Stock Exchange and the Securities and Exchange Commission for an "independent director" and, in addition, is (i) a "non-employee" director within the meaning of Rule 16b-3(b)(3) (or any successor rule) promulgated under the Exchange Act and (ii) an "outside director" within the meaning of Treasury Regulation Section 1.162-27(e)(3) under Section 162(m) of the Code.

(b) *Authority*. The Committee is authorized, subject to the provisions of the Plan, to establish such rules and regulations as it deems necessary for the proper administration of the Plan and, in its sole discretion, to make such determinations, valuations and interpretations and to take such action in connection with the Plan and any Awards (as hereinafter defined) granted hereunder as it deems necessary or advisable. All determinations and interpretations made by the Committee shall be binding and conclusive on all participants and their legal representatives.

(c) *Indemnification*. No member of the Committee and no employee of the Company shall be liable for any act or failure to act hereunder, or for any act or failure to act hereunder by any other member or employee or by any agent to whom duties in connection with the administration of this Plan have been delegated, except in circumstances involving his or her bad faith or willful misconduct. The Company shall indemnify members of the Committee and any agent of the Committee who is an employee of the Company, or of a subsidiary or an Affiliate against any and all liabilities or expenses to which they may be subjected by reason of any act or failure to act with respect to their duties on behalf of the Plan, except in circumstances involving such person's bad faith or willful misconduct. For purposes of this Plan, "Affiliate(s)" means any entity that controls, is controlled by or is under common control with the Company; *provided, however*, that neither the Disputed Claims Reserve, the Disputed Claims Overseers, the Plan Administrator nor the Disbursing Agent, as those terms are defined in Fifth Amended Joint Plan of Affiliated Debtors In Re Enron Corp. et al., shall be an Affiliate.

(d) *Delegation and Advisers*. The Committee may delegate to one or more of its members, or to one or more employees or agents, such duties and authorities as it may deem advisable including the authority to make grants as permitted by applicable law, the rules of the Securities and Exchange Commission (the "SEC") and any requirements of the New York Stock Exchange (the "NYSE"), and the Committee, or any person to whom it has delegated duties or authorities as aforesaid, may employ one or more persons to render advice with respect to any responsibility the Committee or such person may have under the Plan. The Committee may employ such legal or other counsel, consultants and agents as it may deem desirable for the administration of the Plan and may rely upon any opinion or computation received from any such counsel, consultant or agent. Expenses incurred by the Committee in the engagement of such counsel, consultant or agent shall be paid by the Company, or the subsidiary or Affiliate whose employees have benefited from the Plan, as determined by the Committee.

**5. Type of Awards.** Awards under the Plan may be granted in any one or a combination of (a) Stock Options, (b) Stock Appreciation Rights, (c) Restricted Stock Awards, and (d) Stock Units (each as described below, and collectively, the "Awards"). Awards may, as determined by the Committee in its discretion, constitute Performance-Based Awards, as described in Section 13 hereof.

**6. Participants**. Participants will consist of (i) such officers and key employees of the Company and its subsidiaries and Affiliates as the Committee in its sole discretion determines to be significantly responsible for the success and future growth and profitability of the Company and whom the Committee may designate from time to time to receive Awards under the Plan and (ii) each director of the Company who is not otherwise an employee of the Company or any of its subsidiaries and whom the Committee may designate from time to time to receive Awards under the Plan. Designation of a participant in any year shall not require the Committee to designate such person to receive an Award in any other year or, once designated, to receive the same type or amount of Award as granted to the participant in any other year. The Committee shall consider such factors as it deems pertinent in selecting participants and in determining the type and amount of their respective Awards.

**7. Grant Agreements.**

(a) Awards granted under the Plan shall be evidenced by an agreement ("Grant Agreement") that shall provide such terms and conditions, as determined by the Committee in its sole discretion, *provided, however,* that in the event of any conflict between the provisions of the Plan and any such Grant Agreement, the provisions of the Plan shall prevail.

(b) The Grant Agreement will determine the effect on an Award of the disability, death, retirement, involuntary termination, termination for cause or other termination of employment or service of a participant and the extent to which, and the period during which, the participant's legal representative, guardian or beneficiary may receive payment of an Award or exercise rights thereunder. If the relevant Grant Agreement does not provide otherwise, however, the following default rules shall apply:

(i) vested Stock Option and Stock Appreciation Rights held by a participant shall be exercisable for a period of 90 days following the date the participant ceases to be an employee or director of the Company, its subsidiaries and Affiliates;

(ii) unvested Stock Option, Stock Appreciation Rights, Restricted Stock Awards and Stock Units held by a participant shall be forfeited on the date the participant ceases to be an employee or director of the Company, its subsidiaries and Affiliates.

(c) Subject to Section 13(e), the Committee, in its sole discretion, may modify a Grant Agreement, provided any such modification will not materially adversely affect the economic interests of the participant unless the Committee shall have obtained the written consent of the participant. Notwithstanding the foregoing, the Committee shall not reduce the exercise price of a Stock Option or Stock Appreciation Right (other than under Section 15) without the approval of the Company's shareholders.

(d) Grant Agreements under the Plan need not be identical.

**8. Stock Options.**

(a) *Generally*. At any time, the Committee may grant, in its discretion, awards of stock options that will enable the holder to purchase a number of shares of Common Stock from the Company, at set terms (a "Stock Option"). Stock Options may be incentive stock options ("Incentive Stock Options"), within the meaning of Section 422 of the Code, or Stock Options which do not constitute Incentive Stock Options ("Nonqualified Stock Options"). The Committee will have the authority to grant to any participant one or more Incentive Stock Options and/or Nonqualified Stock Options. Each Stock Option shall be subject to such terms and conditions, including vesting, consistent with the Plan as the Committee may provide in the Grant Agreement, subject to the following limitations:

(b) *Exercise Price*. Each Stock Option granted hereunder shall have such per-share exercise price as the Committee may determine in the Grant Agreement, but such exercise price may not be less than "Fair Market Value" (as defined in Section 8(g) below) on the date the Stock Option is granted, except as provided in Section 11(c).

(c) *Payment of Exercise Price*. The option exercise price may be paid in cash or, in the discretion of the Committee and in accordance with any requirements established by the Committee, by the delivery of shares of Common Stock of the Company then owned by the participant. In the discretion of the Committee and in accordance with any requirements established by the Committee, payment may also be made by delivering a properly executed exercise notice to the Company together with a copy of irrevocable instructions to a broker to deliver promptly to the Company the amount of sale or loan proceeds to pay the exercise price.

(d) *Exercise Period*. Stock Options granted under the Plan shall be exercisable at such time or times and subject to such terms and conditions, including vesting, as shall be determined by the Committee in the Grant Agreement.

(e) *Limitations on Incentive Stock Options*. Incentive Stock Options may be granted only to participants who are employees of the Company or of a "Parent Corporation" or "Subsidiary Corporation" (as defined in Sections 424(e) and (f) of the Code, respectively) at the date of grant. The aggregate "Fair Market Value" (as defined and determined as of the time the Stock Option is granted in accordance with Section 8(g) below) of the Common Stock with respect to which Incentive Stock Options are exercisable for the first time by a participant during any calendar year (under all option plans of the Company and of any Parent Corporation or Subsidiary Corporation) shall not exceed one hundred thousand dollars ($100,000). For purposes of the preceding sentence, Incentive Stock Options will be taken into account in the order in which they are granted. The per-share exercise price of an Incentive Stock Option shall not be less than one hundred percent (100%) of the Fair Market Value of the Common Stock on the date of grant, and no Incentive Stock Option may be exercised later than ten (10) years after the date it is granted.

(f) *Additional Limitations on Incentive Stock Options for Ten Percent Shareholders*. Incentive Stock Options may not be granted to any participant who, at the time of grant, owns stock possessing (after the application of the attribution rules of Section 424(d) of the Code) more than ten percent (10%) of the total combined voting power of all classes of stock of the Company or any Parent Corporation or Subsidiary Corporation, unless the exercise price of the option is fixed at not less than one hundred ten percent (110%) of the Fair Market Value of the Common Stock on the date of grant and the exercise of such option is prohibited by its terms after the expiration of five (5) years from the date of grant of such option.

(g) *Fair Market Value*. For purposes of this Plan and any Awards granted hereunder, "Fair Market Value" shall be the closing price of the Common Stock on the relevant date (or on the last preceding trading date if Common Stock was not traded on such date) if the Common Stock is readily tradable on a national securities exchange or other market system, and if the Common Stock is not readily tradable, Fair Market Value shall mean the amount determined in good faith by the Committee as the fair market value of the Common Stock.

**9. Stock Appreciation Rights.**

(a) *Generally*. At any time, the Committee may, in its discretion, grant stock appreciation rights with respect to Common Stock ("Stock Appreciation Rights"), including a concurrent grant of Stock Appreciation Rights in tandem with any Stock Option grant. A Stock Appreciation Right means a right to receive a payment in cash or in Common Stock of an amount equal to the excess of (i) the Fair Market Value of a share of Common Stock on the date the right is exercised over (ii) the Fair Market Value of a share of Common Stock on the date the right is granted, all as determined by the Committee. Each Stock Appreciation Right shall be subject to such terms and conditions, including vesting, as the Committee shall impose in the Grant Agreement.

(b) *Exercise Period*. Stock Appreciation Rights granted under the Plan shall be exercisable at such time or times and subject to such terms and conditions, including vesting, as shall be determined by the Committee in the Grant Agreement.

**10. Restricted Stock Awards.**

(a) *Generally*. At any time, the Committee may, in its discretion, grant Awards of Common Stock, subject to restrictions determined by the Committee (a "Restricted Stock Award"). Such Awards may include mandatory payment of any bonus in stock consisting of Common Stock issued or transferred to participants with or without other payments therefor and may be made in consideration of services rendered to the Company or its subsidiaries or Affiliates. A Restricted Stock Award shall be construed as an offer by the Company to the participant to purchase the number of shares of Common Stock subject to the Restricted Stock Award at the purchase price, if any, established therefore.

(b) *Payment of the Purchase Price*. If the Restricted Stock Award requires payment therefor, the purchase price of any shares of Common Stock subject to a Restricted Stock Award may be paid in any manner authorized by the Committee, which may include any manner authorized under the Plan for the payment of the exercise price of a Stock Option.

(c) *Restrictions*. Restricted Stock Awards shall be subject to such terms and conditions, including without limitation time based vesting and/or performance based vesting, restrictions on the sale or other disposition of such shares, and/or the right of the Company to reacquire such shares for no consideration upon termination of the participant's employment within specified periods, as the Committee determines appropriate. The Committee may require the participant to deliver a duly signed stock power, endorsed in blank, relating to the Common Stock covered by such an Award. The Committee may also require that the stock certificates evidencing such shares be held in custody or bear restrictive legends until the restrictions thereon shall have lapsed.

(d) *Rights as a Shareholder*. The Restricted Stock Award shall specify whether the participant shall have, with respect to the shares of Common Stock subject to a Restricted Stock Award, all of the rights of a holder of shares of Common Stock of the Company, including the right to receive dividends and to vote the shares.

**11. Common Stock Available Under the Plan.**

(a) *Basic Limitations*. The aggregate number of shares of Common Stock that may be subject to Awards shall be 4,687,500, subject to any adjustments made in accordance with Section 15 hereof. The maximum number of shares of Common Stock that may be:

(i) the subject of an Award with respect to any individual participant under the Plan during the term of the Plan shall not exceed 2,000,000 (subject to adjustments made in accordance with Section 15 hereof);

(ii) covered by Awards issued under the Plan during a year shall be limited during the first calendar year of the Plan to 1,250,000 and during any year thereafter to 1% of the Company's outstanding Common Stock at the beginning of such year; and

(iii) issued pursuant to Incentive Stock Options awarded under the Plan shall be 1,000,000.

(b) *Additional Shares*. Any shares of Common Stock subject to a Stock Option or Stock Appreciation Right which for any reason is cancelled or terminated without having been exercised, or any shares of Common Stock subject to Restricted Stock Awards or Stock Units which are forfeited, and any shares delivered to the Company as part or full payment for an Award or, to the extent the Committee determines that the availability of Incentive Stock Options under the Plan will not be compromised, to satisfy the Company's withholding obligation with respect to an Award granted under this Plan as payment of a withholding obligation, shall again be available for Awards under the Plan under 11(a). The preceding sentence shall apply only for purposes of determining the aggregate number of shares of Common Stock subject to Awards but shall not apply for purposes of determining the maximum number of shares of Common Stock with respect to which Awards may be granted to any individual participant under the Plan.

(c) *Acquisitions*. In connection with the acquisition of any business by the Company or any of its subsidiaries or Affiliates, any outstanding grants or awards of options, restricted stock or other equity-based compensation pertaining to such business may be assumed or replaced by Awards under the Plan upon such terms and conditions as the Committee determines, including granting of Stock Options or Stock Appreciation Rights with an exercise price below Fair Market Value at the date of the replacement grant.

**12. Stock Units.**

(a) *Generally*. The Committee may, in its discretion, grant "Stock Units" (as defined in subsection (c) below) to participants hereunder. Stock Units may be subject to such terms and conditions, including time based vesting and/or performance based vesting, as the Committee determines appropriate. A Stock Unit granted by the Committee shall provide payment in shares of Common Stock at such time as the Grant Agreement shall specify. Shares of Common Stock issued pursuant to this Section 12 may be issued with or without other payments therefor as may be required by applicable law or such other consideration as may be determined by the Committee. The Committee shall determine whether a participant granted a Stock Unit shall be entitled to a Dividend Equivalent Right (as defined in subsection (c) below).

(b) *Settlement of Stock Units*. Shares of Common Stock representing the Stock Units shall be distributed to the participant upon settlement of the Award pursuant to the Grant Agreement.

(c) *Definitions*. A "Stock Unit" means a notional account representing one (1) share of Common Stock. A "Dividend Equivalent Right" means the right to receive the amount of any dividend paid on the share of Common Stock underlying a Stock Unit, which shall be payable in cash or in the form of additional Stock Units, in the discretion of the Committee.

**13. Performance-Based Awards.**

(a) *Generally*. Any Award granted under the Plan may be granted in a manner such that the Award qualifies for the performance-based compensation exemption of Section 162(m) of the Code ("Performance-Based Awards"). As determined by the Committee in its sole discretion, either the vesting and/or payment of such Performance-Based Awards shall be based on achievement of hurdle rates and/or growth rates in one or more business criteria that apply to the individual participant, one or more business units, or the Company as a whole.

(b) *Business Criteria*. The business criteria shall be as follows, individually or in combination: (1) net earnings; (2) earnings per share; (3) net sales growth; (4) market share; (5) operating profit; (6) earnings before interest and taxes (EBIT); (7) earnings before interest, taxes, depreciation and amortization (EBITDA); (8) gross margin; (9) expense targets; (10) working capital targets relating to inventory and/or accounts receivable; (11) operating margin; (12) return on equity; (13) return on assets; (14) planning accuracy (as measured by comparing planned results to actual results); (15) market price per share; (16) total return to stockholders; (17) cash flow and/or cash flow return on equity; (18) recurring after-tax net income; (19) gross revenues; (20) return on invested capital; (21) safety; (22) cost management; (23) productivity ratios; (24) operating efficiency; (25) accomplishment of mergers, acquisitions, dispositions or similar extraordinary business transactions; (26) bond ratings; (27) economic value added; (28) book value per share; (29) strategic initiatives; (30) employee satisfaction; (31) cash management or asset management metrics; (32) regulatory performance; (33) dividend yield; (34) dividend payout ratio; (35) pre-tax interest coverage; (36) P/E ratio; (37) capitalization targets; (38) customer value/satisfaction; (39) inventory; (40) inventory turns; (41) availability and/or reliability of generation; (42) outage duration; (43) outage frequency; (44) trading floor earnings; (45) budget-to-actual performance; (46) customer growth; (47) funds from operations; (48) interest coverage; (49) funds from operations/average total debt; (50) funds from operations/capital expenditures; (51) total debt/total capital; (52) electric service power quality and reliability, (53) resolution and/or settlement of litigation and other legal proceedings and (54) total equity/total capital. In addition, Performance-Based Awards may include comparisons to the performance of other companies, such performance to be measured by one or more of the foregoing business criteria.

(c) *Establishment of Performance Goals*. With respect to Performance-Based Awards, the Committee shall establish in writing (i) the performance goals applicable to a given period, and such performance goals shall state, in terms of an objective formula or standard, the method for computing the portion of an Award that vests or the number of shares to be delivered to a participant under an Award if such performance goals are obtained, and (ii) the individual employees or class of employees to which such performance goals shall apply, in each case no later than ninety (90) days after the commencement of the applicable performance period (but in no event after twenty-five percent (25%) of such performance period has elapsed).

(d) *Certification of Performance*. No Performance-Based Awards shall be payable to or vest with respect to, as the case may be, any participant for a given period until the Committee certifies in writing that the objective performance goals (and any other material terms) applicable to such period have been satisfied.

(e) *Modification of Performance-Based Awards*. Subject to Section 15(b), with respect to any Awards intended to qualify as Performance-Based Awards, after establishment of a performance goal, the Committee shall not revise such performance goal or increase the amount of compensation payable thereunder upon the attainment of such performance goal (in accordance with the requirements of Section 162(m) of the Code and the regulations thereunder). Notwithstanding the preceding sentence, (i) the Committee may reduce or eliminate the number of shares of Common Stock or cash granted or the number of shares of Common Stock vested upon the attainment of such performance goal, and (ii) the Committee shall disregard or offset the effect of “Extraordinary Items” in determining the attainment of performance goals. For this purpose, “Extraordinary Items” means extraordinary, unusual and/or non-recurring items, including but not limited to, (i) regulatory disallowances or other adjustments, (ii) restructuring or restructuring-related charges, (iii) gains or losses on the disposition of a business or major asset, (iv) changes in regulatory, tax or accounting regulations or laws, (v) resolution and/or settlement of litigation and other legal proceedings or (vi) the effect of a merger or acquisition.

**14. Foreign Laws.** The Committee may grant Awards to individual participants who are subject to the tax laws of nations other than the United States, which Awards may have terms and conditions as determined by the Committee as necessary to comply with applicable foreign laws. The Committee may take any action which it deems advisable to obtain approval of such Awards by the appropriate foreign governmental entity; *provided, however,* that no such Awards may be granted pursuant to this Section 14 and no action may be taken which would result in a violation of the Exchange Act, the Code or any other applicable law.

**15. Adjustment Provisions.**

(a) *Adjustment Generally*. If there shall be any change in the Common Stock of the Company, through merger, consolidation, reorganization, recapitalization, stock dividend, stock split, reverse stock split, split up, spin-off, combination of shares, exchange of shares, dividends or other changes in capital structure, an adjustment shall be made as provided below in (b) to each outstanding Award.

(b) *Modification of Awards*. In the event of any change or distribution described in subsection (a) above, the Committee shall appropriately adjust the number of shares of Common Stock which may be issued pursuant to the Plan, the other limits on Common

Stock issuable under the Plan under Section 11, and the number of shares covered by, and the exercise price of, each outstanding Award; *provided, however,* that any such adjustment to a Performance-Based Award shall not cause the amount of compensation payable thereunder to be increased from what otherwise would have been due upon attainment of the unadjusted award.

(c) Notwithstanding the above, no adjustment to a Stock Option or Stock Appreciation Right shall be made under this Section 15 in a manner that will be treated under Section 409A of the Code as the grant of a new Stock Option or Stock Appreciation Right.

**16. Nontransferability, Title and Other Restrictions.** Except as otherwise specifically provided by the Committee in a Grant Agreement or modification of a Grant Agreement that provides for transfer, each Award granted under the Plan to a participant shall not be transferable otherwise than by will or the laws of descent and distribution, and shall be exercisable, during the participant's lifetime, only by the participant. In the event of the death of a participant, each Award granted to him or her shall be exercisable during such period after his or her death as the Committee shall in its discretion set forth in the Grant Agreement at the date of grant and then only by the executor or administrator of the estate of the deceased participant or the person or persons to whom the deceased participant's rights under the Stock Option or Stock Appreciation Right shall pass by will or the laws of descent and distribution.

**17. Acceleration of Awards.**

(a) In order to preserve a participant's rights under an Award in the event of a Change in Control of the Company or in the event of a fundamental change in the business condition or strategy of the Company, the Committee, in its sole discretion, may, at the time an Award is made or at any time thereafter, take one or more of the following actions: (i) provide for the acceleration of any time period relating to the exercise or payment of the Award, (ii) provide for payment to the participant of cash or other property with a fair market value equal to the amount that would have been received upon the exercise or payment of the Award had the Award been exercised or paid upon such event, (iii) adjust the terms of the Award in a manner determined by the Committee to reflect such event, (iv) cause the Award to be assumed, or new rights substituted therefor, by another entity, or (v) make such other adjustments in the Award as the Committee may consider equitable to the participant and in the best interests of the Company. Further, any Award shall be subject to such conditions as necessary to comply with federal and state securities laws, the performance based exception of Section 162(m) of the Code, or understandings or conditions as to the participant's employment in addition to those specifically provided for under the Plan.

(b) A *"Change in Control"* shall mean any of the following events:

(i) Any person (as such term is used in Section 14(d) of the Exchange Act) becomes the "beneficial owner" (as determined pursuant to Rule 14d-3 under the Exchange Act), directly or indirectly, of securities of the Company representing more than thirty percent (30%) of the combined voting power of the Company's then outstanding voting securities; or

(ii) During any period of two (2) consecutive years (not including any period prior to the execution of this Plan), individuals who at the beginning of such period constitute the members of the Board of Directors and any new director whose election to the Board of Directors or nomination for election to the Board of Directors by the Company's stockholders was approved by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors at the beginning of the period or whose election or nomination for election was previously so approved, cease for any reason to constitute a majority of the Board of Directors; or

(iii) The Company shall merge with or consolidate into any other corporation or entity, other than a merger or consolidation which would result in the holders of the voting securities of the Company outstanding immediately prior thereto holding immediately thereafter securities representing more than fifty percent (50%) of the combined voting power of the voting securities of the Company or such surviving entity outstanding immediately after such merger or consolidation; or

(iv) The stockholders of the Company approve a plan of complete liquidation of the Company or an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets.

Notwithstanding any of the foregoing, the issuance of shares to or the distribution of shares from the "Disputed Claims Reserve" pursuant to the Fifth Amended Joint Plan of Affiliated Debtors In Re Enron Corp. et al. shall not constitute a Change in Control.

(c) Notwithstanding the above, this Section 17 shall not apply to any Award made under the Plan that is subject to Section 409A of the Code to the extent that its application would result in a modification to either the time or form of payment or distribution of such Award as provided for under the terms of the Plan or a Grant Agreement.

**18. Withholding.** All payments or distributions of Awards made pursuant to the Plan shall be net of any amounts required to be withheld pursuant to applicable federal, state and local tax withholding requirements. If the Company proposes or is required to distribute Common Stock pursuant to the Plan, it may require the recipient to remit to it or to the corporation or entity that employs such recipient an amount sufficient to satisfy such tax withholding requirements prior to the delivery of any certificates for such Common Stock. In lieu thereof, the Company or the employing corporation or entity shall have the right to withhold the amount of such taxes from any other sums due or to become due from such corporation to the recipient as the Committee shall prescribe. The Committee may, in its discretion and subject to such rules as it may adopt (including any as may be required to satisfy applicable tax and/or non-tax regulatory requirements), permit an optionee or award or right holder to pay all or a portion of the federal, state and local withholding taxes arising in connection with any Award consisting of shares of Common Stock by electing to have the Company withhold shares of Common Stock having a Fair Market Value equal to the amount of tax to be withheld, such tax calculated at minimum statutory withholding rates.

**19. Employment.** A participant's right, if any, to continue to serve the Company or any of its subsidiaries or Affiliates as a director, officer, employee, or otherwise, shall not be enlarged or otherwise affected by his or her designation as a participant under the Plan.

**20. Unfunded Plan**. Participants shall have no right, title, or interest whatsoever in or to any investments which the Company may make to aid it in meeting its obligations under the Plan. Nothing contained in the Plan, and no action taken pursuant to its provisions, shall create or be construed to create a trust of any kind, or a fiduciary relationship between the Company and any participant, beneficiary, legal representative or any other person. To the extent that any person acquires a right to receive payments from the Company under the Plan, such right shall be no greater than the right of an unsecured general creditor of the Company. All payments to be made hereunder shall be paid from the general funds of the Company and no special or separate fund shall be established and no segregation of assets shall be made to assure payment of such amounts except as expressly set forth in the Plan. The Plan is not intended to be subject to the Employee Retirement Income Security Act of 1974, as amended.

**21. No Fractional Shares.** No fractional shares of Common Stock shall be issued or delivered pursuant to the Plan or any Award. The Committee shall determine whether cash, or Awards, or other property shall be issued or paid in lieu of fractional shares or whether such fractional shares or any rights thereto shall be forfeited or otherwise eliminated.

**22. Duration, Amendment and Termination.** No Award shall be granted after March 31, 2024. The Committee may amend the Plan from time to time or suspend or terminate the Plan at any time. No amendment of the Plan may be made without approval of the stockholders of the Company if such approval is required under the Code, the rules of a stock exchange, or any other applicable laws or regulations.

**23. Award Deferrals.** Participants may elect to defer receipt of shares of Common Stock or amounts payable under an Award in accordance with procedures established by the Committee.

**24. Effect of Code Section 409A.** To the extent that any Award under this plan is or may be considered to involve a nonqualified deferred compensation plan or deferral subject to Section 409A of the Code, the terms and administration of such Award shall comply with the provisions of such Section, applicable IRS guidance and good faith reasonable interpretations thereof and, to the extent necessary, shall be modified, replaced, or terminated in the discretion of the Committee.

**25. Compliance with Securities Laws.** Notwithstanding any other provision of the Plan, the Company shall have no liability to deliver any shares of Common Stock under the Plan or make any other distribution of benefits under the Plan unless such delivery or distribution would comply with all applicable laws (including, without limitation, the requirements of the Securities Act of 1933), and the applicable requirements of any securities exchange or similar entity.

**26. Governing Law.** This Plan, Awards granted hereunder and actions taken in connection herewith shall be governed and construed in accordance with the laws of the state of Oregon.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ Anne F. Mersereau
Name: Anne F. Mersereau
Title: Vice President, Human Resources, Diversity and Inclusion

**Exhibit 31.1**

**CERTIFICATION**

I, James J. Piro, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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 period presented in this report;

4. The registrant’s other certifying officer 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 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: | July 27, 2017 | By: | /s/ James J. Piro |
| | | | James J. Piro |
| | | | *President and Chief Executive Officer* |

**Exhibit 31.2**

**CERTIFICATION**

I, James F. Lobdell, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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 period presented in this report;

4. The registrant's other certifying officer 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 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: July 27, 2017

By: /s/ James F. Lobdell

James F. Lobdell

*Senior Vice President of Finance,*
*Chief Financial Officer and Treasurer*

**Exhibit 32**

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

We, James J. Piro, President and Chief Executive Officer, and James F. Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the “Company”), hereby certify that the Company’s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017, as filed with the Securities and Exchange Commission on July 28, 2017 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the “Report”), fully complies with the requirements of that section.

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

| | |
|---|---|
| /s/ James J. Piro | /s/ James F. Lobdell |
| James J. Piro | James F. Lobdell |
| *President and Chief Executive Officer* | *Senior Vice President of Finance, Chief Financial Officer and Treasurer* |

| | | | |
|---|---|---|---|
| Date: | July 27, 2017 | Date: | July 27, 2017 |