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, 2016**

or

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

For the transition period from ____________________ to ____________________

Commission File Number: **001-5532-99**

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

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

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

Number of shares of common stock outstanding as of July 22, 2016 is 88,921,050 shares.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED June 30, 2016

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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
Biglow Canyon	Biglow Canyon Wind Farm
Carty	Carty Generating Station 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
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMBs	First Mortgage Bonds
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
PW1	Port Westward Unit 1 natural gas-fired generating plant
PW2	Port Westward Unit 2 natural gas-fired flexible capacity generating plant
RPS	Renewable Portfolio Standard
S&P	Standard and Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
Tucannon River	Tucannon River Wind Farm
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,	
	2016	2015	2016	2015
Revenues, net	$ 428	$ 450	$ 915	$ 923
Operating expenses:				
Purchased power and fuel	126	148	275	309
Generation, transmission and distribution	64	66	130	128
Administrative and other	61	60	122	120
Depreciation and amortization	83	76	165	151
Taxes other than income taxes	30	28	60	58
Total operating expenses	364	378	752	766
Income from operations	64	72	163	157
Interest expense, net	27	28	54	58
Other income:				
Allowance for equity funds used during construction	8	5	15	9
Miscellaneous income (expense), net	1	1	—	2
Other income, net	9	6	15	11
Income before income tax expense	46	50	124	110
Income tax expense	9	15	26	25
Net income and Comprehensive income	$ 37	$ 35	$ 98	$ 85
Weighted-average shares outstanding (in thousands):				
Basic	88,902	80,745	88,867	79,515
Diluted	88,902	80,745	88,867	79,515
Earnings per share:				
Basic	$ 0.42	$ 0.44	$ 1.10	$ 1.07
Diluted	$ 0.42	$ 0.44	$ 1.10	$ 1.07
Dividends declared per common share	$ 0.32	$ 0.30	$ 0.62	$ 0.58

See accompanying notes to condensed consolidated financial statements.

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

	June 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 93	$ 4
Accounts receivable, net	124	158
Unbilled revenues	70	95
Inventories	87	83
Regulatory assets—current	74	129
Other current assets	64	88
Total current assets	**512**	**557**
Electric utility plant, net	6,284	6,012
Regulatory assets—noncurrent	525	524
Nuclear decommissioning trust	41	40
Non-qualified benefit plan trust	33	33
Other noncurrent assets	51	44
Total assets	**$ 7,446**	**$ 7,210**

See accompanying notes to condensed consolidated financial statements.

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

	June 30, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 114	$ 98
Liabilities from price risk management activities—current	81	130
Short-term debt	—	6
Current portion of long-term debt	—	133
Accrued expenses and other current liabilities	247	259
Total current liabilities	**442**	**626**
Long-term debt, net of current portion	2,324	2,060
Regulatory liabilities—noncurrent	949	928
Deferred income taxes	649	632
Unfunded status of pension and postretirement plans	264	259
Liabilities from price risk management activities—noncurrent	171	161
Asset retirement obligations	155	151
Non-qualified benefit plan liabilities	106	106
Other noncurrent liabilities	83	29
Total liabilities	**5,143**	**4,952**
Commitments and contingencies (see notes)		
Equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of June 30, 2016 and December 31, 2015	—	—
Common stock, no par value, 160,000,000 shares authorized; 88,920,756 and 88,792,751 shares issued and outstanding as of June 30, 2016 and December 31, 2015, respectively	1,198	1,196
Accumulated other comprehensive loss	(8)	(8)
Retained earnings	1,113	1,070
Total equity	**2,303**	**2,258**
Total liabilities and equity	**$ 7,446**	**$ 7,210**

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,	
	2016	**2015**
Cash flows from operating activities:		
Net income	$ 98	$ 85
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	165	151
(Decrease) increase in net liabilities from price risk management activities	(46)	63
Regulatory deferrals—price risk management activities	46	(63)
Deferred income taxes	20	22
Pension and other postretirement benefits	14	19
Allowance for equity funds used during construction	(15)	(9)
Other non-cash income and expenses, net	9	13
Changes in working capital:		
Decrease in accounts receivable and unbilled revenues	59	32
Increase in inventories	(4)	(19)
Decrease (increase) in margin deposits, net	18	(17)
Decrease in accounts payable and accrued liabilities	(13)	(22)
Other working capital items, net	6	7
Other, net	(19)	(14)
Net cash provided by operating activities	**338**	**248**
Cash flows from investing activities:		
Capital expenditures	(319)	(313)
Distribution from Nuclear decommissioning trust	—	50
Sales tax refund received related to Tucannon River Wind Farm	—	23
Sales of Nuclear decommissioning trust securities	11	7
Purchases of Nuclear decommissioning trust securities	(11)	(7)
Other, net	—	2
Net cash used in investing activities	**(319)**	**(238)**

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,	
	2016	**2015**
Cash flows from financing activities:		
Proceeds from issuance of common stock, net of issuance costs	$ —	$ 271
Proceeds from issuance of long-term debt	265	145
Payments on long-term debt	(133)	(387)
Change in short-term debt	(6)	—
Dividends paid	(53)	(44)
Payments on capital leases	(2)	—
Debt issuance costs	(1)	—
Net cash provided by (used in) financing activities	**70**	**(15)**
Increase (Decrease) in cash and cash equivalents	89	(5)
Cash and cash equivalents, beginning of period	4	127
Cash and cash equivalents, end of period	**$ 93**	**$ 122**
Supplemental cash flow information is as follows:		
Cash paid for interest, net of amounts capitalized	$ 49	$ 56
Cash paid for income taxes	7	1
Non-cash investing and financing activities:		
Accrued capital additions	53	58
Accrued dividends payable	29	27
Assets obtained under capital lease	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, 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. PGE's corporate headquarters is located in Portland, Oregon and its approximately 4,000 square mile, state-approved service area allocation is located entirely within the State of Oregon, encompassing 52 incorporated cities, of which Portland and Salem are the largest. As of June 30, 2016, PGE served 859,497 retail customers with a service area population of approximately 1.8 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 2016 presentation, PGE has reclassified Regulatory deferral of settled derivative instruments of $2 million to Other non-cash income and expenses, net within the operating activities section of the condensed consolidated statement of cash flows for the six months ended June 30, 2015.

The financial information included herein for the three and six months ended June 30, 2016 and 2015 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, 2015 is derived from the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2015, included in Item 8 of PGE's Annual Report on Form 10-K, filed with the SEC on February 12, 2016, which should be read in conjunction with such condensed consolidated financial statements.

Comprehensive Income

PGE had no material components of other comprehensive income to report for the three and six month periods ended June 30, 2016 and 2015.

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 or as a cumulative-effect adjustment as of the date of adoption, which was originally January 1, 2017 for the Company. In August 2015, the Financial Accounting Standards Board (FASB) issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date* (ASU 2014-14) that defers the effective date by one year, although it permits early adoption as of the original effective date. The Company plans to adopt this ASU on January 1, 2018 and is in the process of evaluating its planned transition method and the impact to its consolidated financial position, consolidated results of operations, and consolidated cash flows of the adoption of ASU 2014-09.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 330), Simplifying the Measurement of Inventory* (ASU 2015-11), which changes the measurement principle for inventory from the lower of cost or market to lower of cost and net realizable value. Net realizable value is defined as the “estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation.” ASU 2015-11 eliminates the guidance that entities consider replacement cost or net realizable value less an approximately normal profit margin in the subsequent measurement of inventory when cost is determined on a first-in, first-out or average cost basis. For calendar year-end public entities, this update will be effective for annual periods beginning January 1, 2017, including interim periods within those annual periods. Early adoption is permitted. The Company does not expect the adoption of this guidance to have a material impact to its consolidated financial position, consolidated results of operations, and consolidated cash flows.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments-Overall (Subtopic 825-10), Recognition and Measurement of Financial Assets and Financial Liabilities* (ASU 2016-01), which enhances the reporting model for certain financial instruments and related disclosures. The main provisions of this ASU affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. For calendar year-end public entities, this update will be effective for annual periods beginning January 1, 2018, including interim periods within those annual periods. Early adoption is permitted, in certain circumstances. The Company does not expect the adoption of this guidance to have a material impact to its consolidated financial position, consolidated results of operations, and consolidated cash flows.

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 2016, the FASB issued ASU 2016-09, *Compensation-Stock Compensation (Topic 718), Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09), which is designed to simplify the presentation and accounting for certain income tax effects, employer tax withholding requirements, forfeiture assumptions, and statement of cash flows presentation related to share-based payment awards. Under this standard, all excess tax benefits and tax deficiencies should be recognized within the income statement, and excess tax benefits should be recognized regardless of whether the benefit reduces taxes payable in the current period. The update also allows reporting entities to make a policy election regarding its accounting for forfeitures either by estimating the number of awards that are expected to vest or account for forfeitures when they occur. Within the statement of cash flows, this update will now require tax windfalls to be classified along with other income tax cash flows as an operating activity, and cash payments made on behalf of employees when directly withholding shares for tax-withholding purposes should be classified as a financing activity. Most of the provisions of this update require transition on a modified retrospective basis by means of a cumulative-effect adjustment to equity as of the beginning of the period in which the guidance is adopted. For calendar year-end public entities, the update will be effective for annual periods beginning January 1, 2017, and interim periods within those annual periods. 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 2016-09.

Recently Adopted Accounting Pronouncements

In April 2015, the FASB issued ASU 2015-03, *Interest-Imputation of Interest (Subtopic 835-30)* (ASU 2015-03), which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The Company has retrospectively adopted the provisions of ASU 2015-03 as of January 1, 2016, which was the original effective date for calendar year-end, public entities. As a result, unamortized debt expense of $12 million and $11 million at June 30, 2016 and December 31, 2015, respectively, have been reclassified from Other noncurrent assets to a deduction of Long-term debt, net of current portion on the condensed consolidated balance sheets. Adoption of this guidance had no impact on the Company's consolidated results of operations or consolidated cash flows. In August 2015, the FASB issued ASU 2015-15, *Interest-Imputation of Interest (Subtopic 835-30): Presentation of Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements-Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting (SEC Update)* (ASU 2015-15), which clarifies that the SEC staff would "not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement" given the lack of guidance on this topic in ASU 2015-03. Therefore, as allowed under this update, the Company records debt issuance costs associated with its line-of-credit arrangements as an asset within Other current assets, and amortizes the costs over the term of the agreement.

In May 2015, the FASB issued ASU 2015-07, *Fair Value Measurement (Topic 820), Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), which removes the requirement to categorize within the fair value hierarchy investments for which fair value is measured using the net asset value per share as a practical expedient. The amendments also remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share as a practical expedient. Instead, such disclosures are restricted only to investments that the entity has decided to measure using the practical expedient. The Company has retrospectively adopted the provisions of this update as of January 1, 2016, which was the original effective date for calendar year-end, public entities. As a result, certain investments have been retrospectively reclassified within the Company's fair value disclosures of its Nuclear decommissioning trust and Non-qualified benefit plan trust. See Note 3, Fair Value of Financial Instruments for more information. The Company also anticipates that adoption of this standard will require certain benefit plan assets to be reclassified in disclosures made in the Company's Annual Report on Form 10-K. The adoption of this guidance had no impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

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 for use in generating plants. Fuel inventories include natural gas, coal, and oil. Periodically, the Company assesses the realizability of inventory for purposes of determining that inventory is recorded at the lower of average cost or market.

Other Current Assets

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

	June 30, 2016	December 31, 2015
Prepaid expenses	$ 35	$ 43
Margin deposits	15	33
Assets from price risk management activities	12	10
Other	2	2
Other current assets	$ 64	$ 88

Electric Utility Plant, Net

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

	June 30, 2016	December 31, 2015
Electric utility plant	$ 8,743	$ 8,560
Construction work-in-progress	746	545
Total cost	9,489	9,105
Less: accumulated depreciation and amortization	(3,205)	(3,093)
Electric utility plant, net	$ 6,284	$ 6,012

Accumulated depreciation and amortization in the table above includes accumulated amortization related to intangible assets of $249 million and $227 million as of June 30, 2016 and December 31, 2015, respectively.

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

Amortization expense related to intangible assets was $10 million and $9 million for the three months ended June 30, 2016 and 2015, respectively, and $22 million and $18 million for the six months ended June 30, 2016 and 2015, respectively. The Company's intangible assets primarily consist of computer software development and hydro licensing costs.

Capital Lease—PGE has entered into agreements to purchase natural gas transportation capacity to serve the Carty Generating Station (Carty), a 440 MW natural gas-fired baseload resource located in eastern Oregon, adjacent to the Boardman coal-fired generating plant. A new 24-mile natural gas pipeline, Carty Lateral, was constructed to serve the Carty facility. The Company has entered into a 30-year agreement to purchase the entire capacity of Carty Lateral, which is approximately 175,000 decatherms per day. At the end of the initial contract term, the Company has the option to renew the agreement in continuous three-year increments with at least 24-months prior written notice. For accounting purposes, this transportation capacity agreement is treated as a capital lease.

As of June 30, 2016, a capital lease asset of $57 million was reflected within Electric utility plant, and accumulated amortization of such assets of $2 million reflected within Accumulated depreciation and amortization in the table above. The present value of the future minimum lease payments due under the agreement included $3 million within Accrued expenses and other current liabilities and $52 million in Other noncurrent liabilities on the condensed consolidated balance sheets. For ratemaking purposes capital leases are treated as operating leases; therefore, in accordance with the accounting rules for regulated operations, the amortization of the leased asset is based on the rental payments recovered from customers. Also for ratemaking purposes, such rental payments were capitalized to the Carty project prior to its in service date of July 29, 2016. Amortization of the leased asset of $2 million and interest expense of $3 million has been capitalized to Construction work-in-progress (CWIP) as of June 30, 2016.

For the remainder of 2016, PGE expects $3 million in minimum lease payments, with $2 million imputed interest and present value of net minimum lease payments of $1 million. As of June 30, 2016, PGE's estimated future minimum lease payments, for the following five years and thereafter, net of administrative costs such as property taxes, insurance and maintenance are as follows (in millions):

	Payments Due						
	2017	2018	2019	2020	2021	Thereafter	Total
Total minimum lease payments	$ 7	$ 6	$ 6	$ 6	$ 6	$ 78	$ 109
Less imputed interest							55
Present value of net minimum lease payments							$ 54

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, 2016		December 31, 2015	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Price risk management	$ 69	$ 166	$ 120	$ 161
Pension and other postretirement plans	—	231	—	239
Deferred income taxes	—	83	—	86
Debt issuance costs	—	23	—	16
Other	5	22	9	22
Total regulatory assets	$ 74	$ 525	$ 129	$ 524
Regulatory liabilities:				
Asset retirement removal costs	$ —	$ 861	$ —	$ 837
Trojan decommissioning activities	26	8	17	15
Asset retirement obligations	—	47	—	45
Other	30	33	38	31
Total regulatory liabilities	$ 56 *	$ 949	$ 55 *	$ 928

* 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, 2016	December 31, 2015
Regulatory liabilities—current	$ 56	$ 55
Accrued employee compensation and benefits	45	51
Accrued interest payable	25	25
Accrued dividends payable	29	28
Accrued taxes payable	23	25
Other	69	75
Total accrued expenses and other current liabilities	$ 247	$ 259

Credit Facilities

As of June 30, 2016, PGE had a $500 million revolving credit facility scheduled to expire in November 2019.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. The revolving credit facility contains provisions for two one-year extensions subject to approval by the banks, requires annual fees based on PGE’s unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65% of total capitalization. As of June 30, 2016, PGE was in compliance with this covenant with a 51.1% 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, 2016, PGE had no borrowings, commercial paper, or letters of credit issued. As of June 30, 2016, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities that provide a total of $160 million capacity under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these four facilities, $92 million of letters of credit were outstanding, as of June 30, 2016.

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

In May 2016, PGE entered into an unsecured credit agreement with certain financial institutions, under which the Company may obtain three separate term loans in an aggregate principal amount of $200 million. During the second quarter of 2016, PGE obtained the following two term loans:

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

The Company has until October 31, 2016 to obtain the third term loan in the amount of up to $75 million. The term loan interest rates are set at the beginning of the interest period for periods of 1-month, 3-months or 6-months, as selected by PGE and are based on the London Interbank Offered Rate (LIBOR) plus 63 basis points, approximately 1.1% as of June 30, 2016, with no other fees.

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

During the six months ended June 30, 2016, PGE had the following First Mortgage Bonds (FMBs) long-term debt transactions, all of which occurred in early January:

- Issued $140 million of 2.51% Series FMBs due 2021;
- Repaid $75 million of 5.80% Series FMBs, due in 2018; and
- Repaid $58 million of 3.81% Series FMBs, due in 2017.

Due to the anticipated repayment of the $133 million in early January 2016, this amount of long-term debt was classified as current on the Company's condensed consolidated balance sheets as of December 31, 2015.

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,	
	2016	2015	2016	2015
Service cost	4	5	8	9
Interest cost	8	8	16	16
Expected return on plan assets	(10)	(10)	(20)	(20)
Amortization of net actuarial loss	4	5	8	10
Net periodic benefit cost	$ 6	$ 8	$ 12	$ 15

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, 2016 and December 31, 2015, 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 reporting date.

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

Level 3 Pricing inputs include significant inputs 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. Pursuant to the adoption of ASU 2015-07, *Fair Value Measurement (Topic 820), Disclosures for Investments in Certain Entities that Calculate Net Asset Value per share (or Its Equivalent)*, as disclosed in Note 1, Basis of Presentation, assets measured at fair value using net asset value (NAV) as a practical expedient are not categorized in the fair value hierarchy. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements, and prior period amounts have been retrospectively reclassified to conform to current presentation.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all 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, 2016 and 2015, except those transfers from Level 3 to Level 2 presented in this note.

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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, 2016				
	Level 1	Level 2	Level 3	Other[2]	Total
Assets:					
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	$ 4	$ 9	$ —	$ —	$ 13
Corporate credit	—	9	—	—	9
Money market funds measured at NAV[2]	—	—	—	19	19
Non-qualified benefit plan trust: [3]					
Equity securities—domestic	3	—	—	—	3
Debt securities—domestic government	1	—	—	—	1
Money market funds measured at NAV[2]	—	—	—	1	1
Collective trust—domestic equity measured at NAV[2]	—	—	—	2	2
Assets from price risk management activities: [1] [4]					
Electricity	—	8	1	—	9
Natural gas	—	8	—	—	8
	$ 8	$ 34	$ 1	$ 22	$ 65
Liabilities from price risk management activities: [1] [4]					
Electricity	$ —	$ 7	$ 145	$ —	$ 152
Natural gas	—	86	14	—	100
	$ —	$ 93	$ 159	$ —	$ 252

(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.

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

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in Regulatory assets or Regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure, and have been retrospectively reclassified pursuant to the implementation of ASU 2015-07. For further information see Note 1, Basis of Presentation.
(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 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 reporting date.

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

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

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. Money market funds are not classified in the fair value hierarchy since they are valued at NAV as a practical expedient. 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 invests in equity securities. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value as a practical expedient. A majority of the funds provide for daily liquidity with appropriate written notice. One fund allows for withdrawal from all accounts as of the last day on each calendar month, with at least 10 days' prior written notice, and provides for a 95% payment to be made within 30 days, and the balance paid after the annual fund audit is complete. Common and collective trusts are not classified in the fair value hierarchy as they are valued at NAV as a practical expedient.

Assets and liabilities from price risk management activities are recorded at fair value in PGE's 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 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:

Commodity Contracts	Fair Value: Assets	Fair Value: Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit: Low	Price per Unit: High	Price per Unit: Weighted Average
	(in millions)						
As of June 30, 2016:							
Electricity physical forwards	$ —	$ 144	Discounted cash flow	Electricity forward price (per MWh)	$ 10.75	$ 53.80	$ 28.67
Natural gas financial swaps	—	14	Discounted cash flow	Natural gas forward price (per Decatherm)	2.02	3.66	2.54
Electricity financial futures	1	1	Discounted cash flow	Electricity forward price (per MWh)	19.61	34.25	28.15
	$ 1	$ 159					
As of December 31, 2015:							
Electricity physical forwards	$ —	$ 105	Discounted cash flow	Electricity forward price (per MWh)	$ 8.50	$ 84.47	$ 30.69
Natural gas financial swaps	—	14	Discounted cash flow	Natural gas forward price (per Decatherm)	2.06	3.70	2.54
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	9.98	27.36	19.26
	$ —	$ 119					

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

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

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

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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,	
	2016	2015	2016	2015
Balance as of the beginning of the period	$ 131	148	$ 119	$ 100
Net realized and unrealized losses*	28	20	40	70
Transfers out of Level 3 to Level 2	(1)	—	(1)	(2)
Balance as of the end of the period	$ 158	$ 168	$ 158	$ 168

* 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, 2016 and 2015, 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 Level 3 in the fair value hierarchy 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, 2016, the carrying amount of PGE’s long-term debt was $2,324 million, net of $12 million of unamortized debt expense, and its estimated aggregate fair value was $2,908 million, classified as Level 2 in the fair value hierarchy. As of December 31, 2015, the carrying amount of PGE’s long-term debt was $2,193 million, net of $11 million of unamortized debt expense, and its estimated aggregate fair value was $2,455 million classified as Level 2 in the fair value hierarchy.

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 and manage risk. Such activities include purchases and sales of both power and fuel resulting from economic dispatch decisions for Company-owned generation. As a result, 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.

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PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign currency exchange rate risk in order to reduce volatility in NVPC for its retail customers. These derivative instruments may include forwards, 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), PGE 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, 2016	December 31, 2015
Current assets:		
Commodity contracts:		
Electricity	$ 8	$ 7
Natural gas	4	3
Total current derivative assets	12 (1)	10 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	1	—
Natural gas	4	—
Total noncurrent derivative assets	5 (2)	— (2)
Total derivative assets not designated as hedging instruments	$ 17	$ 10
Total derivative assets	$ 17	$ 10
Current liabilities:		
Commodity contracts:		
Electricity	$ 14	$ 36
Natural gas	67	94
Total current derivative liabilities	81	130
Noncurrent liabilities:		
Commodity contracts:		
Electricity	138	97
Natural gas	33	64
Total noncurrent derivative liabilities	171	161
Total derivative liabilities not designated as hedging instruments	$ 252	$ 291
Total derivative liabilities	$ 252	$ 291

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

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

	June 30, 2016		December 31, 2015	
Commodity contracts:				
Electricity	7	MWh	12	MWh
Natural gas	130	Decatherms	124	Decatherms
Foreign currency	$ 21	Canadian	$ 7	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 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, 2016 and December 31, 2015, gross amounts included as Price risk management liabilities subject to master netting agreements were $148 million and $111 million, respectively, for which PGE posted collateral of $14 million, which consisted entirely of letters of credit. As of June 30, 2016, of the gross amounts recognized, $144 million was for electricity and $4 million was for natural gas compared to $104 million for electricity and $7 million for natural gas recognized as of December 31, 2015.

Net realized and unrealized losses (gains) on derivative transactions not designated as hedging instruments are recorded 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,	
	2016	2015	2016	2015
Commodity contracts:				
Electricity	$ 27	$ 29	$ 52	$ 70
Natural Gas	(41)	—	(24)	44
Foreign currency exchange	$ —	$ —	$ (1)	$ —

Net unrealized and certain net realized losses (gains) presented in the preceding table 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, 2016 and 2015, net gains of $18 million and net losses of $33 million have been offset, respectively. Net losses of $16 million and $116 million have been offset for the six month periods ended June 30, 2016 and 2015, 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, 2016 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2016	2017	2018	2019	2020	Thereafter	Total
Commodity contracts:							
Electricity	$ 3	$ 6	$ 7	$ 7	$ 7	$ 113	$ 143
Natural gas	46	34	9	3	—	—	92
Net unrealized loss	$ 49	$ 40	$ 16	$ 10	$ 7	$ 113	$ 235

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PGE's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and Standard and Poor's Ratings Services (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, 2016 was $249 million, for which PGE has posted $60 million in collateral, consisting of $49 million in letters of credit and $11 million in cash. If the credit-risk-related contingent features underlying these agreements were triggered at June 30, 2016, the cash requirement to either post as collateral or settle the instruments immediately would have been $230 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, 2016	December 31, 2015
Assets from price risk management activities:		
Counterparty A	22%	5%
Counterparty B	21	59
Counterparty C	6	10
	49%	74%
Liabilities from price risk management activities:		
Counterparty D	57%	36%
Counterparty E	9	10
Counterparty F	7	10
	73%	56%

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) unvested employee stock purchase plan shares and ii) contingently issuable time-based and performance-based restricted stock units, along with associated dividend equivalent rights. 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, 2016, unvested performance-based restricted stock units and related dividend equivalent rights of approximately 305,000 were excluded from the dilutive calculation because the performance goals had not been met, with 306,000 excluded for the three and six month periods ended June 30, 2015.

Net income is the same for both the basic and diluted earnings per share computations. The reconciliations of 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,	
	2016	2015	2016	2015
Weighted-average common shares outstanding—basic	88,902	80,745	88,867	79,515
Dilutive effect of potential common shares	—	—	—	—
Weighted-average common shares outstanding—diluted	88,902	80,745	88,867	79,515

NOTE 6: EQUITY

The activity in equity during the six months ended June 30, 2016 and 2015 is as follows (dollars in millions):

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Shares	Amount			
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
Balances as of December 31, 2014	78,228,339	$ 918	$ (7)	$ 1,000	$ 1,911
Issuances of common stock, net of issuance costs of $12	10,400,000	271	—	—	271
Issuances of shares pursuant to equity-based plans	137,290	1	—	—	1
Stock-based compensation	—	1	—	—	1
Dividends declared	—	—	—	(48)	(48)
Net income	—	—	—	85	85
Balances as of June 30, 2015	88,765,629	$ 1,191	$ (7)	$ 1,037	$ 2,221

During the second quarter of 2015, PGE physically settled in full an equity forward sale agreement, with the issuance of 10,400,000 shares of common stock in exchange for net proceeds of $271 million.

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 consolidated financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. The Company may seek regulatory recovery of certain costs that are incurred in connection with such matters, although there can be no assurance that such recovery would be granted.

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

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

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

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

Trojan Investment Recovery Class Actions

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

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

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

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

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

The OSC further stated that if the OPUC determined that it 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 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 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. PGE opposed the request to amend. On February 22, 2016, the Circuit Court denied the plaintiff's motion to amend the complaint and on March 16, 2016, 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 appeal, management believes that it is reasonably possible that such a loss to the Company could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine the amount of any such loss.

Pacific Northwest Refund Proceeding

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

On remand, in 2011 and thereafter, the FERC issued several procedural orders that established an evidentiary hearing, defined the scope of the hearing, expanded the refund period to include January 1, 2000 through December 24, 2000 for certain types of claims, and described the burden of proof that must be met to justify abrogation of the contracts at issue and the imposition of refunds. Those orders included a finding by the FERC that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome either by: i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract; or ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest. The FERC also held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Refund proponents appealed these procedural orders at the Ninth Circuit. On December 17, 2015, the

Ninth Circuit held that the FERC reasonably applied the *Mobile-Sierra* presumption to the class of contracts at issue in the proceedings and dismissed evidentiary challenges related to the scope of the proceeding. Plaintiffs on behalf of the California Energy Resources Scheduling division of the California Department of Water Resources filed a request for rehearing on February 1, 2016. By order issued April 18, 2016, the Ninth Circuit denied plaintiffs' request for panel rehearing of its decision regarding application of the *Mobile-Sierra* presumption.

In response to the evidence and arguments presented during the hearing, in May 2015, the FERC issued an order finding that the refund proponents had failed to meet the *Mobile-Sierra* burden with respect to all but one respondent. In December 2015, the FERC denied all requests for rehearing of its order. With respect to the remaining respondent, FERC ordered additional proceedings, and a January 2016 revised initial decision has now recommended that certain contracts by such respondent be subject to refund.

The Company has settled all of the direct claims asserted against it in the proceedings for an immaterial amount. The settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which have been described by the FERC as "sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund." However, the remaining respondent subject to the revised initial decision has stated on the record that it will not pursue ripple claims, and on February 1, 2016, the Acting Chief Administrative Law Judge issued an order holding that the issue of ripple claims is terminated for purposes of Phase II of these proceedings. Therefore, unless the current FERC orders are overturned or modified on appeal, the Company does not believe that it will incur any material loss in connection with this matter.

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

EPA Investigation of Portland Harbor

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

The Portland Harbor site remedial investigation (RI) has been completed pursuant to an Administrative Order on Consent between the EPA and several PRPs known as the Lower Willamette Group (LWG), which does not include PGE.

The EPA has finalized the feasibility study (FS), along with the RI, and these documents will provide the framework for the EPA to determine a clean-up remedy for Portland Harbor that will be documented in a Record of Decision (ROD).

In June 2016, the EPA issued a proposed clean-up plan for comment. The EPA's preferred alternative set forth in the proposed plan has an estimated present value cost of $746 million and would take approximately seven years to construct with additional time needed for monitored natural recovery to occur. This cost estimate is approximately half of the estimate that EPA presented in November 2015 for a similar preferred alternative that had an estimated present value cost of $1.5 billion. A substantial portion of the EPA's reduction in estimated costs relates to revised assumptions and estimates concerning the costs of various activities. There is a 90-day public comment period through September 6, 2016, subject to potential extension if the EPA chooses. The Company currently expects the EPA to issue a determination of its preferred remedy in a final ROD in late 2016. However, responsibility for funding and implementing the EPA's selected remedy is not expected to be determined until several years thereafter. PGE is participating in a voluntary process to develop a method for allocation of costs.

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

After the claimed damages at a site are assessed, the NRD trustees may seek to negotiate legal settlements or take other legal actions against the parties responsible for the damages. Funds from such settlements must be used to restore injured resources and may also compensate the trustees for costs incurred in assessing the damages. It is uncertain what portion, if any, PGE may be held responsible related to Portland Harbor.

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

On July 15, 2016, the Company filed a deferral application with the OPUC to allow for the deferral of the future environmental remediation costs, as well as, seek authorization to establish a regulatory cost recovery mechanism for such environmental costs. This Portland Harbor Environmental Remediation Balancing Account (PHERA) mechanism would allow the Company to recover incurred environmental expenditures through a combination of third-party proceeds, such as insurance recoveries, and through customer prices, as necessary. The mechanism would establish annual prudency reviews of environmental expenditures and be subject to an annual earnings test. The amounts to be recovered under the PHERA is dependent upon future expenditures, third-party recoveries, prudency reviews, and impact of potential earnings reviews.

Alleged Violation of Environmental Regulations at Colstrip

On March 6, 2013, the Sierra Club and the Montana Environmental Information Center (MEIC) sued the co-owners of the Colstrip Steam Electric Station (CSES), including PGE, for alleged violations of the Clean Air Act (CAA), including New Source Review, Title V, and opacity requirements, as well as other alleged violations of various environmental regulations. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The plaintiffs asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and that the owners violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality (MDEQ). The plaintiffs sought relief that included an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits. In addition, plaintiffs sought civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter. Between 2013 and 2015, the parties filed various motions to dismiss, motions for summary judgment and amended complaints.

On July 12, 2016, the parties reached a settlement for this case in a consent decree filed in the U.S. District Court in Montana. Pursuant to the terms of the settlement, all alleged violations against the CSES owners, including PGE, have been dropped, and the owners of Colstrip Power Plant Units 1 and 2 have agreed that on or before July 1, 2022, Units 1 and 2, in which PGE has no ownership interest, shall permanently cease operations and shall not, thereafter, burn any fuel in or otherwise operate its boilers. Colstrip Units 3 and 4 are to remain operational, and all other equipment, except for boilers, of Units 1 and 2 may continue to be used to support the operation of Units 3 and 4. The settlement is subject to approval by the District Court. The Company does not anticipate that the settlement will have a material impact on the Company's ownership interest in Units 3 and 4.

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: CARTY GENERATING STATION

Carty Placed In Service—On July 29, 2016, the Company placed into service the Carty Generating Station (Carty), a 440 MW baseload natural gas-fired generating plant in Eastern Oregon, located adjacent to the Boardman coal plant. As of June 30, 2016, PGE had $587 million, including $59 million of AFDC, included in CWIP for the project as compared to $424 million, including $41 million of AFDC, as of December 31, 2015. The final order issued by the OPUC on November 3, 2015 in connection with the Company's 2016 GRC, authorized the inclusion in customer prices of capital costs for Carty of up to $514 million, including AFDC, as well as Carty's operating costs, at such time that the plant is placed in service, provided that occurred by July 31, 2016. As Carty was placed in service on July 29, 2016, the Company has been authorized to include in customer prices, effective August 1, 2016, its revenue requirement necessary to allow for recovery of capital costs of up to $514 million, as well as operating costs, associated with the construction and operation of Carty.

Construction Litigation—In 2013, the Company entered into an agreement (Construction Agreement) with its engineering, procurement and construction contractor - Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership, an affiliate of Abengoa S.A. (collectively, the “Contractor”) - for the construction of Carty.

On December 18, 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Liberty Mutual Insurance Company and Zurich American Insurance Company (hereinafter referred to collectively as the “Sureties”), have provided a performance bond of $145.6 million (Performance Bond) under the Construction Agreement.

On January 28, 2016, the Company received notice from the International Chamber of Commerce International Court of Arbitration that Abengoa S.A. had submitted a Request for Arbitration. In the request, Abengoa S.A. alleged that the Company’s termination of the Construction Agreement was wrongful and in breach of the agreement terms and does not give rise to any liability of Abengoa S.A. under the terms of a guaranty in favor of PGE and pursuant to which Abengoa S.A. agreed to guaranty certain obligations of the Contractor under the Construction Agreement. Abengoa S.A. is also seeking to implead the Contractor into this arbitration. PGE disagrees with the assertions in the Request for Arbitration and on February 29, 2016 filed a Complaint and Motion for Preliminary Injunction in the U.S. District Court for the District of Oregon seeking to have the arbitration claim dismissed on the grounds that the Company has not made a demand under the Abengoa S.A. guaranty, and therefore the matter is not ripe for arbitration. On March 28, 2016, Abengoa S.A. and several of its foreign affiliates filed petitions for recognition under Chapter 15 of the U.S. Bankruptcy Code requesting interim relief, including an injunction precluding the prosecution of any proceedings against the Chapter 15 debtors. On March 29, 2016, a number of Abengoa S.A.’s U.S. subsidiaries, including the four entities that collectively comprise the Contractor, filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. As a result, on April 5, 2016, the U.S. District Court issued an order stating that the Company’s District Court action against Abengoa S.A. was stayed. In June 2016, the Company filed with the bankruptcy court in the Chapter 11 proceeding a motion for relief from stay with respect to the four entities that collectively comprise the Contractor, which, if granted would allow the Company to bring claims against such entities in the U.S. District Court.

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

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

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

On April 15, 2016, the Sureties filed a motion to stay this U.S. District Court proceeding, alleging that PGE’s claims should be addressed in the arbitration proceeding initiated by Abengoa S.A. and referenced above because PGE’s claims are intertwined with the issues involved in such arbitration and all parties necessary to resolve PGE’s claims are parties to the arbitration. PGE opposed the motion and filed a motion to enjoin the Sureties from pursuing, in the ICC arbitration proceeding, claims relating to the Performance Bond. On July 27, 2016, the court denied the Sureties’ motion to stay and granted PGE’s motion for a preliminary injunction.

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

PGE currently estimates the total cost of Carty could range from $640 million to $660 million, including AFDC. This cost estimate does not reflect any amounts that may be received from the Sureties pursuant to the Performance Bond. This estimate includes approximately $15 million of lien claims filed against PGE for goods and services provided under contracts with the former Contractor. The Company believes these liens are invalid and is contesting the claims in the courts.

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

As actual project costs for Carty exceed $514 million, including AFDC, the Company will incur a higher cost of service than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation and interest expense. On July 29, 2016, the Company 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 to delay its review of this deferral request until the Company’s claims against the Sureties have been resolved. Until such time, the effects of this higher cost of service will be recognized in the Company’s results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP. Any amounts approved by the OPUC for recovery under the deferral filing will be recognized in earnings in the period of such approval.

NOTE 9: 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, 2016, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the 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 expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis including, but not limited to, management’s examination of historical operating trends and data contained either in internal records or available from third parties, but there can be no assurance that PGE’s expectations, beliefs, or projections will be achieved or accomplished.

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

- governmental policies and regulatory audits, investigations and actions, including those of the FERC and 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 and Note 8 - Carty Generating Station, 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 affecting PGE’s power generating facilities, including forced outages, hydro, and wind conditions, and disruptions of fuel supply, any of which may cause the Company to incur repair costs or purchase replacement power at increased costs;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, either of which could result in the Company’s inability to recover project costs;
- volatility in wholesale power and natural gas prices, which could require PGE to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to power and natural gas purchase agreements;

- changes in the availability and price of wholesale power and fuels, including natural gas, coal, and oil, and the impact of such changes on the Company’s power costs;
- capital market conditions, including availability of capital, volatility of interest rates, reductions in demand for investment-grade commercial paper, as well as changes in PGE’s credit ratings, any of which could have an impact on the Company’s cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, and the repayments of maturing debt;
- future laws, regulations, and proceedings that could increase the Company’s costs of operating its thermal generating plants, or affect the operations of such plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- changes in, and compliance with, environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company’s costs, or adversely affect its operations;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE’s service territory;
- the effectiveness of PGE’s risk management policies and procedures;
- declines in the fair value of securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company’s generation and transmission facilities or information technology systems, or result in the release of confidential customer and proprietary 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;
- political and economic conditions;
- natural disasters and other risks such as earthquake, flood, drought, lightning, wind, and fire;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

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

Overview

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide an understanding of the business environment, results of operations, and financial condition of PGE. 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, 2015, 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.

The Company is in the process of finalizing its 2016 IRP, which will address resource needs over the next 20 years. The areas of focus for the plan include, among other topics, additional resources needed to meet Oregon's Renewable Portfolio Standard (RPS) requirements and to replace energy from Boardman, which is scheduled to cease coal-fired operations at the end of 2020. In March 2016, the state of Oregon passed a new law referred to as the Oregon Clean Electricity and Coal Transition Plan (OCEP), which, among other things, increased the renewable energy thresholds under the RPS. For further information on the OCEP, see the *"Legal, Regulatory, and Environmental Matters"* section of this Overview.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 (PATH) was signed into law, and among other things, extended the production tax credit (PTC) for five years. Under the extension, PTC's related to renewable projects that begin construction before January 1, 2017 and make continuous progress towards completion under one of the methods prescribed by the Internal Revenue Service (IRS) will receive 100% of the PTC value. The credits will be phased out over the remaining 3-year period. Renewable projects that begin construction in 2017 will receive 80% of the PTC value, renewable projects that begin construction in 2018 will receive 60% of the PTC value, and renewable projects that begin construction in 2019 will receive 40% of the PTC value. In an attempt to capture the full benefit of the PTC's and meet the Company's future RPS requirements and resource needs, on May 4, 2016, the Company filed a petition with the Public Utility Commission of Oregon (OPUC) seeking approval of an accelerated Request for Proposals (RFP) for additional renewable resources in the second half of 2016. The petition requested authority to obtain up to 175 average megawatts of renewable power, and included consideration of both asset-ownership and purchase power agreement options.

Based on input from a public comment period, on June 7, 2016 the Commission decided to take no action at that time on whether to approve the RFP, and extended the public comment period until June 28, 2016, in order to help inform PGE on potential changes to the RFP. The Commission encouraged the Company and other stakeholders to engage in timely dialogue with respect to any issues or concerns regarding the proposed RFP. Following numerous discussions with the various parties, on July 13, 2016, the Company submitted an amended application to the OPUC requesting approval of an updated version of the RFP. The revised filing included several changes to the RFP requested by stakeholders, but the parties did not reach a consensus on all issues. On July 26, 2016 the OPUC Staff issued a report which found that the Renewable RFP appears fair and conforms with the competitive bidding guidelines, except for concerns around the alignment of the RFP with the Company's most recently acknowledged IRP. At a public meeting on July 29, 2016, the OPUC again decided to take no action with regard to the Company's request to approve the RFP. In light of the questions expressed by the OPUC, Staff and other parties, the Company is suspending the Renewable RFP until such time as we are able to complete further analysis and determine the appropriate timing for seeking approval of a revised RFP schedule. The Company is unable to predict the outcome of this matter.

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.

Carty Generating Station—On July 29, 2016, Carty, a 440 MW natural gas-fired baseload resource in Eastern Oregon, was placed into service. As of June 30, 2016, PGE had $587 million, including $59 million of AFDC, included in CWIP for the project. The Company currently estimates that the total capital expenditures for Carty, including AFDC, will be approximately $640 million to $660 million. This cost estimate does not reflect any amounts that may be received from the Sureties pursuant to the Performance Bond or from the Contractor or Abengoa S.A.

The final order issued by the OPUC on November 3, 2015 in connection with the Company's 2016 General Rate Case authorized the inclusion in customer prices of capital costs for Carty of up to $514 million, including AFDC, as well as Carty's operating costs, at such time that the plant was placed into service, provided that occurred by July 31, 2016. As Carty was placed in service on July 29, 2016, the Company has been authorized to include in customer prices, effective August 1, 2016, its revenue requirement necessary to allow for recovery of capital costs of up to $514 million, as well as operating costs, associated with the construction and operation of Carty. This increase consists of an $85 million annualized increase related to cost recovery of Carty and a $41 million annualized decrease ($17 million over the remainder of 2016) related to the amortization of certain customer credits through supplemental tariffs. As actual project costs for Carty have exceeded $514 million, including AFDC, the Company will incur a higher cost of service than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation and interest expense. On July 29, 2016, the Company also requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the incremental capital costs for Carty starting from its in service date to the date that such amounts are approved in a subsequent GRC proceeding. The Company has requested the OPUC to delay its review of this deferral request until the Company's claims against the Sureties have been resolved. Until such time, the effects of this higher cost of service will be recognized in the Company's results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP. 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 proceedings related to Carty, see Note 8, Carty Generating Station, in the Notes to the Condensed Consolidated Financial Statements.

Capital Requirements and Financing—In total, the Company's 2016 capital expenditures are expected to approximate $646 million, which includes the high end of the estimated range of capital expenditures to complete Carty of $194 million to $214 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 2016 capital requirements with cash from operations during 2016, which is expected to range from $480 million to $520 million, and the issuance of short-term and long-term debt securities. These amounts do not include any estimated proceeds that may be received from the Sureties pursuant to the Company's complaint for breach of contract filed against the Sureties on March 23, 2016. For additional information, see *"Liquidity"* and *"Debt and Equity Financings"* in the Liquidity and Capital Resources section of this Item 2.

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 is a winter-peaking utility that typically experiences its highest retail energy sales during the winter heating season, although a slightly lower peak occurs in the summer that generally results from air conditioning demand. Retail customer price changes and 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 1.2% decrease in retail energy deliveries for the six months ended June 30, 2016 compared with the six months ended June 30, 2015 was driven by a decrease in industrial energy deliveries partially offset by an increase in residential and commercial energy deliveries. The increases in residential and commercial energy deliveries were driven by winter weather that was colder than the prior year and a continued increase in the average number of residential and commercial customers served, partially offset by a cooler start to the summer cooling season than the prior year comparative period. The decrease in industrial demand was primarily due to the closure of a large paper customer that ceased operations in late 2015.

During the first quarter of 2016, heating degree-days, an indication of the extent to which customers are likely to have used electricity for heating, although 15% below average, were 7% above the first quarter of 2015. According to the National Oceanic and Atmospheric Administration's climatological rankings, for the three month period of January through March, the State of Oregon experienced the warmest average temperatures on record during 2015. As a result of the historic warm weather in the prior year, residential energy deliveries, which are weather sensitive, for the first quarter of 2016, were 8.9% higher than the first quarter of 2015.

In the second quarter 2016, heating degree-days, were 42% below average and 21% below the second quarter of 2015. Cooling degree-days, an indication of the extent to which customers are likely to have used electricity for cooling, although 120% above average, were 26% below the second quarter of 2015.

On a year-to-date basis, the Company experienced a 1.3% and 1.0% increase in the average number of residential and commercial customers served, respectively, which also contributed to higher deliveries. One additional day in the first half of 2016 due to leap year also provided an increase of approximately 0.6% in retail energy deliveries. The decrease in industrial demand was primarily due to the closure of a large paper customer that ceased operations in late 2015.

The following table, which includes direct access customers purchasing their energy from Electricity Service Suppliers (ESSs), presents the average number of retail customers by customer class, and corresponding energy deliveries, for the periods indicated:

	Six Months Ended June 30,				
	2016		2015		
	Average Number of Customers	Retail Energy Deliveries*	Average Number of Customers	Retail Energy Deliveries*	% Increase (Decrease)in Energy Deliveries
Residential	750,124	3,660	740,188	3,559	2.8 %
Commercial (PGE sales only)	105,764	3,397	104,748	3,384	0.4 %
Direct access	315	262	334	256	2.3 %
Total Commercial	106,079	3,659	105,082	3,640	0.5 %
Industrial (PGE sales only)	189	1,414	201	1,692	(16.4)%
Direct access	63	606	61	563	7.6 %
Total Industrial	252	2,020	262	2,255	(10.4)%
Total (PGE sales only)	856,077	8,471	845,137	8,635	(1.9)%
Total Direct access	378	868	395	819	6.0 %
Total	856,455	9,339	845,532	9,454	(1.2)%

* In thousands of MWh.

Energy efficiency and conservation efforts by retail customers continue to influence total energy deliveries, although to the extent average usage per customer varies from expectations established in the latest GRC, the financial impacts to the Company of any such reduction in usage is largely mitigated by the decoupling mechanism.

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 continuously based on numerous factors including plant availability, customer demand, river flows, wind conditions, and current wholesale prices.

PGE's thermal 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 approximated 93% and 90% during the first half of 2016 and 2015, 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% and 93% during the first half of 2016 and 2015, respectively.

During the first half of 2016, the Company's generating plants provided approximately 54% of its retail load requirement compared with 49% in the first half of 2015. The increase in the proportion of power generated to meet the Company's retail load requirement was largely the result of increased production from the Company's hydro, wind, and thermal generation facilities during the first half of 2016 relative to the first half of 2015.

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, 2016, energy received from these hydro resources increased by 19% compared to the six months ended June 30, 2015. Also, energy received from these hydro resources exceeded projected levels included in PGE's AUT by 1% for the six months ended June 30, 2016 and fell below projected levels by 6% for the six months ended June 30, 2015, and provided 20% and 19% of the Company's retail load requirement for the six months ended June 30, 2016 and 2015, respectively. Energy from hydro resources is expected to approximate levels projected in the AUT for 2016.

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, 2016, energy received from these wind generating resources increased 23% compared to the six months ended June 30, 2015. Energy received from these wind generating resources fell short of that projected in PGE's AUT by 10% for the six months ended June 30, 2016 and 27% for the six months ended June 30, 2015, and provided approximately 11% and 9% of the Company's retail load requirement during the six months ended June 30, 2016 and 2015, respectively. Energy from wind resources is expected to be below projected levels included in the AUT for 2016.

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. To the extent actual annual NVPC, subject to certain adjustments, is above or below the deadband, which is a defined range from $15 million below to $30 million above 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, 2016, actual NVPC was $6 million below baseline NVPC. Based on forecast data, NVPC for the year ending December 31, 2016 is currently estimated to be slightly above the baseline NVPC, but within the deadband range. Accordingly, no estimated collection from, or refund to, customers is expected under the PCAM for 2016.

For the six months ended June 30, 2015, actual NVPC was $2 million below baseline NVPC. For the year ended December 31, 2015, actual NVPC was $3 million below baseline NVPC, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded pursuant to PCAM for 2015.

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.

For additional information regarding the above and other matters, see Note 7 - Contingencies and Note 8 - Carty Generating Station, in the Notes to Condensed Consolidated Financial Statements.

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

Under the new law, PGE will be required to:

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

The Company is in the process of evaluating the impacts and incorporating the effects of the legislation into its 2016 Integrated Resource Plan (2016 IRP), which is anticipated to be filed with the OPUC in the second half of 2016.

Ballot Measure 97—The State of Oregon will have a citizens' initiative on the November 2016 ballot that proposes a gross receipts tax on businesses with annual Oregon sales in excess of $25 million. As proposed, the initiative would impose a minimum tax of 2.5% on Oregon gross receipts in excess of $25 million. If passed, the initiative would impact the Company's tax liability and could potentially increase the cost to procure goods and services from companies also impacted by the initiative. The Company is in the process of assessing these and other potential impacts on the Company's financial position and results of operations, and anticipates that any incremental costs associated with the initiative would be recovered through customer prices.

Clean Power Plan—On August 3, 2015, the EPA released a final rule, which it calls the "Clean Power Plan." Under the final rule, each state would have to reduce the carbon intensity of its power sector on a state-wide basis by an amount specified by the EPA. The rule establishes state-specific goals in terms of pounds of carbon dioxide emitted per MWh of energy produced. The rule is intended to result in a reduction of carbon emissions from existing power plants across all states to approximately 32% below 2005 levels by 2030.

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

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 Clean Power Plan pending the resolution of legal challenges to the rule. The Company cannot predict the impact of the stay, the ultimate outcome of the legal challenges, or whether Oregon and Montana will continue to develop implementation plans for the rule's previously required September 6, 2016 deadline.

The following discussion highlights certain regulatory items that have impacted the Company's revenues, results of operations, or cash flows for the first half of 2016 compared to the first half of 2015, 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. As part of its 2016 GRC, PGE included a projected $31 million reduction in power costs that was approved by the OPUC and reflected in customer prices effective January 1, 2016.

Under the PCAM for 2015, 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 2015 during the latter half of 2016 with a decision expected in the fourth quarter of 2016. Any resulting refund to or collection from customers would occur during 2017.

On July 15, 2016 the Company filed an update to its 2017 AUT filing of expected power costs which would result in an overall price decrease of 1.4% for cost of service customers. Pursuant to the schedule established in the proceeding, updates of the forecast will occur through mid-November which could change this estimate. As a result of the OCEP legislation described above, PGE’s 2017 AUT filing includes projected PTCs for the 2017 calendar year. Any adjustment in customer prices would be expected to occur January 1, 2017.

Renewable Resource Costs—Pursuant to its renewable adjustment clause mechanism (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.

On April 1, 2015, PGE submitted to the OPUC a RAC filing that requested revenue requirements related to a new, 1.2 MW solar facility. Concurrent with this filing, PGE also requested authorization to engage in a property sale as part of a sale-leaseback agreement for the facility. The Company estimates that overall annual impact to customer prices of this RAC filing will be an approximately $2 million reduction in revenues over a one year period beginning January 1, 2016. On October 2, 2015, the OPUC issued an order approving the deferral of costs associated with the facility. On March 30, 2016, PGE submitted to the OPUC a RAC filing that requested no significant additions or deferrals for 2016.

Decoupling—The decoupling mechanism, which the OPUC has authorized through 2016, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. In March 2016, PGE filed a request with the OPUC to have the mechanism extended through 2019. The mechanism provides for collection from (or refund to) customers if weather adjusted use per customer is less (or more) than that projected in the Company’s most recent approved general rate case.

Accordingly, collection of the estimated $5 million recorded during 2013 occurred during 2015. Refund of the $5 million recorded during 2014, is expected to occur 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, subject to OPUC approval, is expected to occur over a one year period, which would begin January 1, 2017.

For the six months ended June 30, 2016, the Company has recorded an estimated collection of $3 million. Any resulting collection from (or refund to) customers for the 2016 year would begin January 1, 2018.

General Rate Case—In November 2015, the OPUC issued an order in the Company’s 2016 General Rate Case (GRC), intended primarily to allow recovery of costs associated with the construction and operation of Carty. The net annual revenue requirement increase is effective in two phases, with the first, a $44 million decrease, effective January 1, 2016. See “Carty Generating Station” in the Overview section for discussion regarding the second phase as approved within the order.

Integrated Resource Plan—PGE’s IRP outlines how the Company will meet future customer demand and describes PGE’s future energy supply strategy, reflecting new technologies, market conditions, and regulatory requirements. PGE’s latest IRP (2013 IRP), which was acknowledged by the OPUC in December 2014, and updated in December 2015, includes an “Action Plan” that covers PGE’s proposed actions through 2017. The Company continues to make substantial progress on the Action Plan items, which include the evaluation of PGE’s participation in an Energy Imbalance Market (EIM). In September 2015, the Company announced plans to explore participation in the western EIM, which was launched in 2014 by the California Independent System Operator. The western EIM is a real-time energy wholesale market that automatically dispatches the lowest-cost electricity resources available to meet utility customer needs, while optimizing use of renewable energy over a large geographic area. PGE has signed an agreement, which was approved by the FERC in January 2016, to join the western EIM. The agreement outlines a schedule of activities and milestones over the next two years with the Company's participation in the EIM targeted to begin in the fall of 2017.

PGE is in the process of finalizing its next IRP, which it anticipates filing with the OPUC in the fourth quarter of 2016. The submission will address needs that include additional resources in order to meet the 2020 RPS requirements and to replace energy and capacity from Boardman, which is scheduled to cease coal-fired operations at the end of 2020. Further actions through 2020 are expected to be identified that would offset expiring power purchase agreements and integrate variable energy resources, such as wind or solar generation facilities. The 2016 IRP will also consider the OCEP, which, among other things, increased the RPS requirements for 2025 and future years. For further information, see the *"Legal, Regulatory and Environmental"* section of this Item 2.

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, 2015, filed with the SEC on February 12, 2016.

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,			
	2016		2015		2016		2015	
Revenues, net	$ 428	100%	$ 450	100%	$ 915	100%	$ 923	100%
Purchased power and fuel	126	29	148	33	275	30	309	33
Gross margin	302	71	302	67	640	70	614	67
Other operating expenses:								
Generation, transmission and distribution	64	15	66	15	130	14	128	14
Administrative and other	61	14	60	13	122	13	120	13
Depreciation and amortization	83	19	76	17	165	18	151	17
Taxes other than income taxes	30	7	28	6	60	7	58	6
Total other operating expenses	238	56	230	51	477	52	457	50
Income from operations	64	15	72	16	163	18	157	17
Interest expense*	27	6	28	6	54	6	58	6
Other income:								
Allowance for equity funds used during construction	8	2	5	1	15	2	9	1
Miscellaneous income (expense), net	1	—	1	—	—	—	2	—
Other income, net	9	2	6	1	15	2	11	1
Income before income tax expense	46	11	50	11	124	14	110	12
Income tax expense	9	2	15	3	26	3	25	3
Net income	$ 37	9%	$ 35	8%	$ 98	11%	$ 85	9%

* Net of an allowance for borrowed funds used during construction of $4 million and $3 million for the three months ended June 30, 2016 and 2015, respectively, and $8 million and $6 million for the six months ended June 30, 2016 and 2015.

Net income attributable to PGE was $37 million, or $0.42 per diluted share, for the three months ended June 30, 2016 compared with $35 million, or $0.44 per diluted share, for the three months ended June 30, 2015. The increase in Net income was driven by enhanced power supply operations due to increased wind production and better hydro conditions which resulted in lower NVPC in the second quarter of 2016 when compared to the second quarter of 2015. Actual NVPC was $7 million below the baseline for the second quarter of 2016, while actual NVPC approximated baseline NVPC for the second quarter of 2015. Allowance for equity funds during construction also increased by $3 million due to higher average CWIP balances. These increases were partially offset by a decrease in Retail revenues due to 5.2% lower volumes of retail energy delivered as a result of lower load from mild weather in comparison to the second quarter of 2015. The earnings per share amounts reflect, in part, the impact of an additional 10.4 million common shares issued in June 2015.

Net income attributable to PGE was $98 million, or $1.10 per diluted share, for the six months ended June 30, 2016, compared with $85 million, or $1.07 per diluted share, for the six months ended June 30, 2015. The increase in Net income was driven by a 2.8% increase in residential energy deliveries resulting largely from weather, which, although warmer than average, was cooler than the first half of 2015. Also, NVPC was $6 million below baseline NVPC for the first half of 2016, compared to $2 million below the baseline for the first half of 2015. The differences between actual and baseline NVPC for each period are largely due to decreases in the average variable power cost per MWh compared to projected levels included in the respective AUT. Additionally, allowance for equity funds during construction increased by $6 million in the first half of 2016 in comparison to the first half of 2015 due to higher average CWIP balances. The earnings per share amounts reflect, in part, the impact of an additional 10.4 million common shares issued in June 2015.

Three Months Ended June 30, 2016 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,			
	2016		2015	
Revenues [1] (dollars in millions):				
Retail:				
Residential	191	45%	200	44 %
Commercial	162	38	167	37
Industrial	50	12	57	13
Subtotal	403	95	424	94
Other retail revenues, net	1	—	(4)	(1)
Total retail revenues	404	95	420	93
Wholesale revenues	14	3	18	4
Other operating revenues	10	2	12	3
Total revenues	$ 428	100%	$ 450	100 %
Energy deliveries (MWh in thousands):				
Retail:				
Residential	1,557	30%	1,628	31 %
Commercial	1,695	33	1,753	34
Industrial	717	14	870	18
Subtotal	3,969	76	4,251	82
Direct access:				
Commercial	133	3	127	2
Industrial	323	6	291	6
Subtotal	456	9	418	8
Total retail energy deliveries	4,425	85	4,669	90
Wholesale energy deliveries	773	15	538	10
Total energy deliveries	5,198	100%	5,207	100 %
Average number of retail customers:				
Residential	750,961	88%	740,845	87 %
Commercial	106,656	12	105,674	13
Industrial	190	—	200	—
Direct access	375	—	386	—
Total	858,182	100%	847,105	100 %

(1) Includes revenues from customers who purchase their energy from the Company as well as $7 million in revenues for 2016 and $6 million for 2015 from Direct access customers for transmission and delivery charges only.

Total revenues for the three months ended June 30, 2016 decreased $22 million compared to the three months ended June 30, 2015, comprised primarily of a $16 million decrease in Retail revenues and $4 million decrease in Wholesale revenues.

The change in Retail revenues resulted from the following:

- A $21 million decrease related to 5.2% lower retail energy deliveries due to unfavorable weather conditions and a decrease in deliveries to industrial customers. Energy deliveries to residential and commercial customers decreased 4.4% and 2.8%, respectively, due to the effects of more moderate weather, and energy deliveries to industrial customers decreased 10.4%, largely due to the closure of a large paper customer that ceased operations in late 2015. PGE's 2016 GRC took the loss of this customer into consideration and incorporated its effects into prices and load forecasts resulting in minimal impact on Net income. After adjusting for the effects of weather, total retail energy deliveries were down 5.1% for the three months ended June 30, 2016 compared with the three months ended June 30, 2015; and

- A $5 million increase related to customer refunds that occurred in the second quarter of 2015 that did not reoccur in the second quarter of 2016 in connection with the receipt of proceeds pursuant to the settlement of a legal matter related to the operation of the Independent Spent Fuel Storage Installation (ISFSI) at the Trojan nuclear power plant, which was closed in 1993 (offset in Depreciation and amortization).

Total heating degree-days for the three months ended June 30, 2016 were 21% below the three months ended June 30, 2015 and 42% below average. Total cooling degree-days for the three months ended June 30, 2016 were 26% below the three months ended June 30, 2015 although 120% above average.

The following table indicates the number of heating degree-days for the three months ended June 30, 2016 and 2015, 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		
	2016	**2015**	**Avg.**	**2016**	**2015**	**Avg.**
April	227	361	386	18	2	1
May	109	133	216	31	20	18
June	67	19	87	105	185	51
Totals for the quarter	403	513	689	154	207	70

Wholesale revenues for the three months ended June 30, 2016 decreased 4 million, or 22%, from the three months ended June 30, 2015, and consisted of $12 million decrease related to a 45% decrease in average wholesale price offset by an $8 million increase related to a 44% increase in wholesale sales volume.

Purchased power and fuel expense decreased $22 million, or 15%, for the three months ended June 30, 2016 compared with the three months ended June 30, 2015, and consisted of $21 million related to a 14% decrease in the average variable power cost per MWh and $1 million related to a 1% decrease in total system load.

The decrease in the average variable power cost to $25.46 per MWh in the three months ended June 30, 2016 from $29.65 per MWh in the three months ended June 30, 2015 was driven by a decline in the Company's cost of natural gas to fuel natural gas-fired plants in 2016 compared with 2015, combined with the economic displacement of a greater amount of thermal generation with purchased power which experienced an average variable cost price decrease of 26%. A combined 21% increase in energy received from the Company's wind and hydro generating resources also contributed to the decrease in the average variable power cost per MWh due to more favorable weather conditions.

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,			
	2016		2015	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	360	7%	727	15%
Natural gas	772	16	984	20
Total thermal	1,132	23	1,711	35
Hydro	379	8	318	6
Wind	628	13	515	10
Total generation	2,139	43	2,544	51
Purchased power:				
Term	2,090	42	1,376	27
Hydro	393	8	383	8
Wind	91	2	96	2
Spot	264	5	621	12
Total purchased power	2,838	57	2,476	49
Total system load	4,977	100%	5,020	100%
Less: wholesale sales	(773)		(538)	
Retail load requirement	4,204		4,482	

Energy received from PGE-owned wind generating resources increased 22% in the three months ended June 30, 2016 compared with the same period of 2015 as a result of more favorable wind conditions. Energy received from these wind generating resources represented 15% and 11% of the Company's retail load requirements for the three months ended June 30, 2016 and 2015, respectively. Due to more favorable hydroelectric conditions, energy received from hydro resources during the three months ended June 30, 2016, from both PGE-owned generating plants and purchased from mid-Columbia projects, increased 10% compared with the same period of 2015, and represented 18% and 16% of the Company's retail load requirement for the three months ended June 30, 2016 and 2015, respectively.

The following table presents the forecast of the April-to-September 2016 runoff (issued July 28, 2016), along with actual for 2015, 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):

	Runoff as a Percent of Normal*	
Location	**2016 Forecast**	**2015 Actual**
Columbia River at The Dalles, Oregon	90%	69%
Mid-Columbia River at Grand Coulee, Washington	92	77
Clackamas River at Estacada, Oregon	70	53
Deschutes River at Moody, Oregon	91	85

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

Actual NVPC for the three months ended June 30, 2016 decreased $18 million when compared with the three months ended June 30, 2015. The decrease was driven by a 14% decline in the average variable power cost per MWh, a 1% decrease in total system load, offset by a 22% decrease in wholesale revenues. The decrease in wholesale revenues was driven primarily by a 45% decrease in the average wholesale sales price, partially offset by a 44% increase in wholesale sales volume. For the three months ended June 30, 2016 actual NVPC was $7 million below the baseline, while the three months ended June 30, 2015 actual NVPC approximated baseline NVPC.

Generation, transmission and distribution expense decreased $2 million, or 3%, in the three months ended June 30, 2016 compared with the three months ended June 30, 2015 driven primarily by a $3 million decrease due to the timing of the annual planned outage at Boardman, offset by a $2 million increase in service restoration expenses.

Administrative and other expense increased $1 million, or 2%, in the three months ended June 30, 2016 compared with the three months ended June 30, 2015. The increase was primarily due to a $2 million reduction in the reserve for customer receivables in 2015.

Depreciation and amortization expense increased $7 million in the three months ended June 30, 2016 compared with the three months ended June 30, 2015. The increase was primarily driven by $4 million additional expense due to capital additions, $4 million due to the temporary discontinuance of amortization of credits for the regulatory liability for the Trojan spent fuel settlement, and $4 million resulting from a combination of gains recorded on the sale of assets and other minor items, offset by a $5 million decrease that resulted from the completion of the amortization of the regulatory asset for four capital project deferrals as authorized in the Company’s 2011 GRC. Increases or decreases in expense resulting from amortization of regulatory assets or liabilities are directly offset in revenues.

Interest expense decreased $1 million, or 4%, in the three months ended June 30, 2016 compared with the three months ended June 30, 2015, with $1 million related to a 7% decrease in the average balance of debt outstanding and $1 million related to a higher allowance for borrowed funds used during construction.

Other income, net was $9 million in the three months ended June 30, 2016 compared with $6 million in the three months ended June 30, 2015. The change was due to an increase in the allowance for equity funds used during construction resulting from higher average CWIP balances, primarily related to the Carty project.

Income tax expense was $9 million in the three months ended June 30, 2016 compared with $15 million in the three months ended June 30, 2015, with effective tax rates of 19.6% and 30.0%, respectively. The decrease in income tax expense and effective tax rate was primarily due to lower pre-tax income, an increase in the amount of allowance for equity funds used during construction, and an increase in production tax credits.

Six Months Ended June 30, 2016 Compared with the Six Months Ended June 30, 2015

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,					
	2016			2015		
Revenues [1] (dollars in millions):						
Retail:						
Residential	$	445	49%	$	434	47 %
Commercial		322	35		322	35
Industrial		99	11		113	12
Subtotal		866	95		869	94
Other retail revenues, net		4	1		(2)	—
Total retail revenues		870	95		867	94
Wholesale revenues		26	3		37	4
Other operating revenues		19	2		19	2
Total revenues	$	915	100%	$	923	100 %
Energy deliveries (MWh in thousands):						
Retail:						
Residential		3,660	35%		3,559	34 %
Commercial		3,397	32		3,384	32
Industrial		1,414	13		1,692	16
Subtotal		8,471	80		8,635	82
Direct access:						
Commercial		262	2		256	2
Industrial		606	6		563	5
Subtotal		868	8		819	7
Total retail energy deliveries		9,339	88		9,454	89
Wholesale energy deliveries		1,261	12		1,118	11
Total energy deliveries		10,600	100%		10,572	100 %
Average number of retail customers:						
Residential		750,124	88%		740,188	88 %
Commercial		105,764	12		104,748	12
Industrial		189	—		201	—
Direct access		378	—		395	—
Total		856,455	100%		845,532	100 %

(1) Includes revenues from customers who purchase their energy from the Company as well as $15 million in revenues for 2016 and $14 million for 2015 from Direct access customers for transmission and delivery charges only.

Total revenues for the six months ended June 30, 2016 decreased $8 million compared to the six months ended June 30, 2015, as an $11 million reduction in Wholesale revenues was partially offset by a $3 million increase in Retail revenues.

The change in Retail revenues resulted from the following:

- A $12 million increase due to 1.4% higher retail deliveries after considering the effects of the closure of a large paper customer that ceased operation in late 2015. This increase in year-to-date deliveries is due largely to cooler weather in the first quarter of 2016 when compared to the first quarter 2015, and is partially offset by an $8 million decrease resulting from lower average system delivery prices. After adjusting for the effects of weather, total retail energy deliveries were down 2.1% for the six months ended June 30, 2016 compared with the six months ended June 30, 2015; and
- A net $1 million decrease due to changes to a number of additional supplemental tariff adjustments.

Total heating degree-days for the six months ended June 30, 2016 were comparable to those for the six months ended June 30, 2015 although 22% below average. Total cooling degree-days for the six months ended June 30, 2016 were 26% below those for the six months ended June 30, 2015, although 120% above average.

The following table indicates the number of heating and cooling degree-days for the six months ended June 30, 2016 and 2015, 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**		
	2016	**2015**	**Avg.**	**2016**	**2015**	**Avg.**
First quarter	1,585	1,481	1,866	—	—	—
Second quarter	403	513	689	154	207	70
Year-to-date	1,988	1,994	2,555	154	207	70

Wholesale revenues for the six months ended June 30, 2016 decreased $11 million, or 30%, from the six months ended June 30, 2015, and consisted of $16 million related to a 38% decrease in average wholesale price partially offset by $5 million related to a 13% increase in wholesale sales volume.

Purchased power and fuel expense decreased $34 million, or 11%, for the six months ended June 30, 2016 compared with the six months ended June 30, 2015, and consisted of $34 million related to an 11% decrease in the average variable power cost per MWh while total system load stayed consistent with the comparative period.

The decrease in the average variable power cost to $26.84 per MWh in the six months ended June 30, 2016 from $30.13 per MWh in the six months ended June 30, 2015 was driven by a decline in the Company's cost of natural gas to fuel natural gas-fired plants in 2016 compared with 2015, combined with the economic displacement of a greater amount of thermal generation with purchased power which experienced an average variable cost price decrease of a 13%. In addition, the average variable power cost per MWh from generation sources of energy decreased by 1%, driven primarily by a combined 21% increase in energy received from the Company's wind and hydro generating resources due to more favorable weather conditions.

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,			
	2016		2015	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	1,117	11%	1,211	12%
Natural gas	1,774	17	1,654	16
Total thermal	2,891	28	2,865	28
Hydro	947	9	796	8
Wind	989	10	803	8
Total generation	4,827	47	4,464	44
Purchased power:				
Term	3,576	35	2,876	28
Hydro	838	8	913	9
Wind	150	1	153	1
Spot	866	8	1,861	18
Total purchased power	5,430	53	5,803	56
Total system load	10,257	100%	10,267	100%
Less: wholesale sales	(1,261)		(1,118)	
Retail load requirement	8,996		9,149	

Energy received from PGE-owned wind generating resources increased 23% in the six months ended June 30, 2016 compared with the same period of 2015 as a result of more favorable wind conditions. Energy received from these wind generating resources represented 11% and 9% of the Company's retail load requirements for the six months ended June 30, 2016 and 2015, respectively. Due to more favorable hydroelectric conditions, energy received from hydro resources during the six months ended June 30, 2016, from both PGE-owned generating plants and purchased from mid-Columbia projects, increased 4% compared with the same period of 2015, and represented 20% and 19% of the Company's retail load requirement for the six months ended June 30, 2016 and 2015, respectively.

Actual NVPC for the six months ended June 30, 2016 decreased $23 million when compared with the six months ended June 30, 2015. The decrease was driven by an 11% decrease in the average variable power cost per MWh, offset by a 30% decrease in wholesale revenues. The decrease in wholesale revenues was driven primarily by a 38% decrease in the average wholesale sales price, partially offset by a 13% increase in wholesale sales volume. For the six months ended June 30, 2016 and 2015, actual NVPC was $6 million below and $2 million below baseline NVPC, respectively.

Generation, transmission and distribution expense increased $2 million, or 2%, in the six months ended June 30, 2016 compared with the six months ended June 30, 2015 driven primarily by $2 million higher labor costs, $3 million more service restoration expenses, and $2 million higher information technology expenses, offset by a $4 million decrease due to the timing of the annual planned outage at Boardman.

Administrative and other expense increased $2 million, or 2%, in the six months ended June 30, 2016 compared with the six months ended June 30, 2015. The increase was primarily due to a $1 million increase in compensation and benefits expense.

Depreciation and amortization expense increased $14 million in the six months ended June 30, 2016 compared with the six months ended June 30, 2015. The increase was primarily driven by $8 million additional expense due to capital additions, $8 million due to the temporary discontinuance of amortization of credits for the regulatory liability for the Trojan spent fuel settlement, and $7 million resulting from a combination of gains recorded on the sale of assets and other minor items, offset by a $9 million decrease that resulted from the completion of the amortization of the regulatory asset for four capital project deferrals as authorized in the Company's 2011 GRC. Increases or decreases in expense resulting from amortization of regulatory assets or liabilities are directly offset in revenues.

Interest expense decreased $4 million, or 7%, in the six months ended June 30, 2016 compared with the six months ended June 30, 2015, with $3 million related to a 7% decrease in the average balance of debt outstanding and $2 million related to a higher allowance for borrowed funds used during construction.

Other income, net was $15 million in the six months ended June 30, 2016 compared with $11 million in the six months ended June 30, 2015. The change was due to a $6 million increase in the allowance for equity funds used during construction resulting from higher average CWIP balances, offset by a $2 million decrease in earnings on the non-qualified benefit plan trust assets.

Income tax expense was $26 million in the six months ended June 30, 2016 compared with $25 million in the six months ended June 30, 2015, with effective tax rates of 21.0% and 22.7%, respectively. The increase in income tax expense was primarily due to higher pre-tax income.

Liquidity and Capital Resources

Capital Requirements

The following table presents PGE's estimated capital expenditures and contractual maturities of long-term debt for 2016 through 2020 (in millions, excluding AFDC):

	2016	2017	2018	2019	2020
Ongoing capital expenditures [(1)]	$ 432	$ 398	$ 316	$ 282	$ 301
Carty Generating Station [(2)]	214	—	—	—	—
Total capital expenditures	$ 646 [(3)]	$ 398	$ 316	$ 282	$ 301
Long-term debt maturities	$ —	$ 125	$ —	$ 300	$ —

(1) Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connections. In the 2016 through 2018 years, $115 million relates to the implementation of the Company's new customer information and meter data management systems.
(2) Amount shown for 2016 reflects the high end of the estimated range of capital expenditures to complete Carty, which is $194 million to $214 million, before considering any amount that may be received from the Sureties pursuant to the Performance Bond.
(3) Includes preliminary engineering and removal costs, which are included in other net operating activities in the condensed consolidated statements of cash flows.

For additional information on Carty, see *"Carty Generating Station"* in the Overview section of this Item 2. 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,	
	2016	**2015**
Cash and cash equivalents, beginning of period	$ 4	$ 127
Net cash provided by (used in):		
Operating activities	338	248
Investing activities	(319)	(238)
Financing activities	70	(15)
Increase (Decrease) in cash and cash equivalents	89	(5)
Cash and cash equivalents, end of period	$ 93	$ 122

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, 2016 increased $90 million when compared with the six months ended June 30, 2015. Such increase was largely due to an increase in collections of accounts receivable and unbilled revenues, as well as a decrease in margin deposits. The remaining increase is due to an increase in net income, as well as an increase in depreciation and amortization and other changes in working capital items as a result of amount and timing of transactions.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. PGE estimates that such charges in 2016 will range from $315 million to $325 million. Combined with other sources, total cash expected to be provided by operations is estimated to range from $480 million to $520 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, 2016 increased $81 million when compared with the six months ended June 30, 2015. Such increase was largely due to the distribution from the Nuclear decommission trust of $50 million and sales tax refund from Tucannon River Wind Farm of $23 million that is included for the six months ended June 30, 2015.

The Company plans to make capital expenditures of approximately $646 million in 2016, including $214 million related to the construction of Carty. PGE plans to fund the 2016 capital expenditures with cash expected to be generated from operations during 2016, as discussed above, as well as with proceeds received from the issuances debt securities. For additional information, see *"Capital Requirements"* and *"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, 2016, net cash provided by financing activities consisted primarily of $265 million received from the issuances of FMBs and an unsecured credit agreement, partially offset by repayment of long-term debt of $133 million and the payment of dividends of $53 million. During the six months ended June 30, 2015, net cash used in financing activities consisted of the repayment of FMBs of $387 million and the payment of dividends of $44 million, partially offset by proceeds received from the issuance of common stock of $271 million and FMBs of $145 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 2016 consist of the following:

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

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 2016, PGE expects to fund estimated capital expenditures and maturities of long-term debt with cash from operations (which is expected to range from $480 million to $520 million), issuances of debt securities of up to $415 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.

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

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

Under the revolving credit facility, as of June 30, 2016, PGE had no borrowings, commercial paper outstanding, or letters of credit issued. As of June 30, 2016, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities under which the Company can request letters of credit for original terms not to exceed one year. These facilities provide for a total capacity of $160 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, letters of credit for a total of $92 million were outstanding as of June 30, 2016.

Long-term Debt. During the six months ended June 30, 2016, PGE had the following long-term debt transactions, all of which occurred in early January:

- In January, PGE issued $140 million of 2.51% Series First Mortgage Bonds (FMBs) due 2021;

- In January, PGE repaid $58 million of 3.81% Series FMBs, due in 2017 and $75 million of 5.80% Series FMBs, due in 2018; and
- In May 2016, PGE entered into a $200 million unsecured loan agreement with certain financial institutions. PGE borrowed $50 million under the agreement on May 4, 2016, and an additional $75 million on June 15, 2016. PGE has until October 31, 2016 to borrow the remaining $75 million. The loans are due on November 30, 2017.

As of June 30, 2016, total long-term debt outstanding, net of $12 million of unamortized debt expense, was $2,324 million, with no scheduled maturities classified as current.

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 ratios were 49.2% and 50.7% as of June 30, 2016 and December 31, 2015, respectively.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's Investors Service (Moody's) and Standard and Poor's Ratings Services (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, 2016, PGE had posted approximately $63 million of collateral with these counterparties, consisting of $14 million in cash and $49 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, 2016, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade was approximately $79 million, and decreases to approximately $47 million by December 31, 2016 and to $22 million by December 31, 2017. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade was approximately $140 million at June 30, 2016, and decreases to approximately $88 million by December 31, 2016 and to $62 million by December 31, 2017.

PGE's financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade. However, the cost of borrowing and issuing letters of credit under the credit 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, 2016, under the most restrictive issuance test in the Indenture, the Company could have issued up to approximately $1,129 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, 2016, the Company's debt-to-total capital ratio, as calculated under the credit agreement, was 51.1%.

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 2016 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, 2015, filed with the SEC on February 12, 2016. Such obligations have not changed materially as of June 30, 2016.

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, 2015, filed with the SEC on February 12, 2016.

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, 2016, 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, 2015, filed with the SEC on February 12, 2016 and Part II, Item 1 of the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2016, filed with the SEC on April 29, 2016.

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

On March 16, 2016, the Marion County 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 general judgment of the Circuit Court in the Court of Appeals for the State of Oregon.

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

On July 12, 2016, the parties reached a settlement of this case in a consent decree filed in U.S. District Court in Montana and is currently subject to final approval from the Court. Pursuant to the terms of the settlement, all alleged violations against the CSES owners, including PGE have been dropped, and the owners of Colstrip Power Plant Units 1 and 2 have agreed that on or before July 1, 2022, Units 1 and 2 shall permanently cease operations and shall not, thereafter, burn any fuel in or otherwise operate its boilers. Colstrip Units 3 and 4 are to remain operational, and all other equipment, except for boilers, of Units 1 and 2 may continue to be used to support the operation of Units 3 and 4. The Company does not anticipate that the settlement will have a material impact on its ownership interest in Units 3 and 4.

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

On March 23, 2016, the Company filed a breach of contract action against Liberty Mutual Insurance Company and Zurich American Insurance Company (the “Sureties”). The Company filed the action in response to the Sureties’ denial of liability in whole under the performance bond provided by the Sureties under the construction agreement for the construction of Carty. For additional information on this matter, see Note 8, Carty Generating Station, 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, 2015, filed with the SEC on February 12, 2016.

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).
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: August 2, 2016

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)

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:	August 2, 2016	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:	August 2, 2016	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, 2016, as filed with the Securities and Exchange Commission on August 3, 2016 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the “Report”), fully complies with the requirements of that section.

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

/s/ James J. Piro	/s/ James F. Lobdell
James J. Piro	James F. Lobdell
President and Chief Executive Officer	*Senior Vice President of Finance, Chief Financial Officer and Treasurer*
Date: August 2, 2016	Date: August 2, 2016