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 **September 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 October 17, 2016 is 88,926,854 shares.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED September 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
Boardman	Boardman coal-fired generating plant
Carty	Carty natural gas-fired generating plant
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
CWIP	Construction work-in-progress
EPA	United States Environmental Protection Agency
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMBs	First Mortgage Bonds
GAAP	Accounting principles generally accepted in the United States of America
GRC	General Rate Case
IRP	Integrated Resource Plan
Moody’s	Moody’s Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NVPC	Net Variable Power Costs
OCEP	Oregon Clean Electricity and Coal Transition Plan
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
RPS	Renewable Portfolio Standard
S&P	S&P Global Ratings
SEC	United States Securities and Exchange Commission
Trojan	Trojan nuclear power plant

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Revenues, net	**$ 484**	**$ 476**	**$ 1,399**	**$ 1,399**
Operating expenses:				
Purchased power and fuel	180	181	455	490
Generation, transmission and distribution	69	64	199	192
Administrative and other	63	59	185	179
Depreciation and amortization	79	76	244	227
Taxes other than income taxes	29	28	89	86
Total operating expenses	420	408	1,172	1,174
Income from operations	**64**	**68**	**227**	**225**
Interest expense, net	**28**	**28**	**82**	**86**
Other income:				
Allowance for equity funds used during construction	4	6	19	15
Miscellaneous income (expense), net	—	(2)	—	—
Other income, net	**4**	**4**	**19**	**15**
Income before income tax expense	40	44	164	154
Income tax expense	**6**	**8**	**32**	**33**
Net income and Comprehensive income	**$ 34**	**$ 36**	**$ 132**	**$ 121**
Weighted-average shares outstanding—basic and diluted (in thousands)	88,921	88,766	88,885	82,633
Earnings per share—basic and diluted	$ 0.38	$ 0.40	$ 1.49	$ 1.47
Dividends declared per common share	$ 0.32	$ 0.30	$ 0.94	$ 0.88

See accompanying notes to condensed consolidated financial statements.

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

	September 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 88	$ 4
Accounts receivable, net	140	158
Unbilled revenues	60	95
Inventories	82	83
Regulatory assets—current	65	129
Other current assets	41	88
Total current assets	**476**	**557**
Electric utility plant, net	6,340	6,012
Regulatory assets—noncurrent	515	524
Nuclear decommissioning trust	41	40
Non-qualified benefit plan trust	34	33
Other noncurrent assets	49	44
Total assets	**$ 7,455**	**$ 7,210**

See accompanying notes to condensed consolidated financial statements.

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

	September 30, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 112	$ 98
Liabilities from price risk management activities—current	66	130
Short-term debt	—	6
Current portion of long-term debt	—	133
Accrued expenses and other current liabilities	270	259
Total current liabilities	**448**	**626**
Long-term debt, net of current portion	2,325	2,060
Regulatory liabilities—noncurrent	958	928
Deferred income taxes	644	632
Unfunded status of pension and postretirement plans	267	259
Liabilities from price risk management activities—noncurrent	163	161
Asset retirement obligations	156	151
Non-qualified benefit plan liabilities	105	106
Other noncurrent liabilities	79	29
Total liabilities	**5,145**	**4,952**
Commitments and contingencies (see notes)		
Equity:		
Portland General Electric Company shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of September 30, 2016 and December 31, 2015	—	—
Common stock, no par value, 160,000,000 shares authorized; 88,926,626 and 88,792,751 shares issued and outstanding as of September 30, 2016 and December 31, 2015, respectively	1,199	1,196
Accumulated other comprehensive loss	(7)	(8)
Retained earnings	1,118	1,070
Total equity	**2,310**	**2,258**
Total liabilities and equity	**$ 7,455**	**$ 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)

	Nine Months Ended September 30,	
	2016	**2015**
Cash flows from operating activities:		
Net income	$ 132	$ 121
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	244	227
(Decrease) increase in net liabilities from price risk management activities	(59)	71
Regulatory deferrals—price risk management activities	59	(71)
Deferred income taxes	18	31
Pension and other postretirement benefits	21	25
Allowance for equity funds used during construction	(19)	(15)
Other non-cash income and expenses, net	8	29
Changes in working capital:		
Decrease in accounts receivable and unbilled revenues	53	37
Decrease (increase) in inventories	1	(12)
Decrease (increase) in margin deposits, net	25	(9)
Increase in accounts payable and accrued liabilities	31	13
Other working capital items, net	12	15
Other, net	(29)	(23)
Net cash provided by operating activities	**497**	**439**
Cash flows from investing activities:		
Capital expenditures	(454)	(452)
Distribution from Nuclear decommissioning trust	—	50
Sales tax refund received related to Tucannon River Wind Farm	—	23
Sales of Nuclear decommissioning trust securities	17	11
Purchases of Nuclear decommissioning trust securities	(16)	(10)
Other, net	(1)	1
Net cash used in investing activities	**(454)**	**(377)**

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 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)	(442)
Change in short-term debt	(6)	—
Dividends paid	(82)	(70)
Other	(3)	(1)
Net cash provided by (used in) financing activities	**41**	**(97)**
Increase (Decrease) in cash and cash equivalents	**84**	**(35)**
Cash and cash equivalents, beginning of period	**4**	**127**
Cash and cash equivalents, end of period	**$ 88**	**$ 92**
Supplemental cash flow information is as follows:		
Cash paid for interest, net of amounts capitalized	$ 61	$ 67
Cash paid for income taxes	12	3
Non-cash investing and financing activities:		
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. The Company's corporate headquarters is located in Portland, Oregon and its approximately 4,000 square mile, state-approved service area allocation, located entirely within the State of Oregon, encompasses 51 incorporated cities, of which Portland and Salem are the largest. As of September 30, 2016, PGE served approximately 863,000 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 Cash paid pursuant to the Residential Exchange Program of $3 million to Other, net and Decoupling mechanism deferrals, net of amortization of $10 million to Other non-cash income and expenses, net within the operating activities section of the condensed consolidated statement of cash flows for the nine months ended September 30, 2015.

The financial information included herein for the three and nine months ended September 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 month periods ended September 30, 2016 and 2015. Other comprehensive loss due to the change in compensation retirement benefits liability and amortization, net of taxes was $1 million and none for the nine month periods ended September 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 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 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 August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230), Classification of Certain Cash Receipts and Cash Payments* (ASU 2016-15), with the intention to reduce diversity in practice, as well as simplify elements of classification within the statement of cash flows for certain transactions. The new ASU prescribes specific clarification guidance for the following eight classes of transactions: debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance (COLI) policies, distributions received from equity method investments, beneficial interest in securitization transactions, and separately identifiable cash flows and application of the predominance principal. For calendar year-end public entities, the update will be effective for annual periods beginning January 1, 2018 and requires application using a retrospective transition method. Early adoption is permitted. The Company is in the process of evaluating the impacts of adoption of ASU 2016-15 to the presentation of consolidated cash flows.

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 $11 million at September 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):

	September 30, 2016	December 31, 2015
Prepaid expenses	$ 28	$ 43
Margin deposits	8	33
Assets from price risk management activities	5	10
Other	—	2
Other current assets	$ 41	$ 88

Electric Utility Plant, Net

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

	September 30, 2016	December 31, 2015
Electric utility plant	$ 9,415	$ 8,560
Construction work-in-progress	194	545
Total cost	9,609	9,105
Less: accumulated depreciation and amortization	(3,269)	(3,093)
Electric utility plant, net	$ 6,340	$ 6,012

Accumulated depreciation and amortization in the table above includes accumulated amortization related to intangible assets of $260 million and $227 million as of September 30, 2016 and December 31, 2015, respectively. Amortization expense related to intangible assets was $11 million and $10 million for the three months ended September 30, 2016 and 2015, respectively, and $33 million and $28 million for the nine months ended September 30, 2016 and 2015, respectively. The Company's intangible assets primarily consist of computer software development and hydro licensing costs.

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

Carty Placed In Service—On July 29, 2016, the Company placed Carty into service, a 440 MW baseload natural gas-fired generating plant in Eastern Oregon, located adjacent to the Boardman coal-fired generating plant (Boardman). As of September 30, 2016, PGE had $615 million in plant in service related to Carty as compared to $424 million, as of December 31, 2015 included in Construction work-in-progress (CWIP) for the project. The final order issued by the OPUC on November 3, 2015 in connection with the Company's 2016 General Rate Case (GRC), authorized the inclusion in customer prices of capital costs for Carty of up to $514 million, 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, the revenue requirement necessary to allow for recovery of capital costs of up to $514 million, as well as Carty's operating costs. See Note 7, Contingencies, for further information regarding Carty.

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

As of September 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 and, as a result, amortization of the leased asset of $2 million and interest expense of $3 million was capitalized to CWIP. Beginning August 1, 2016, amortization of the leased asset of $1 million and interest expense of $1 million has been recorded to Purchased power and fuel expense in the condensed consolidated statements of income through September 30, 2016.

For the remainder of 2016, PGE expects $2 million in minimum lease payments, with $1 million of imputed interest and present value of net minimum lease payments of $1 million. As of September 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):

	September 30, 2016		December 31, 2015	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Price risk management	$ 61	$ 161	$ 120	$ 161
Pension and other postretirement plans	—	228	—	239
Deferred income taxes	—	80	—	86
Debt issuance costs	—	23	—	16
Other	4	23	9	22
Total regulatory assets	$ 65	$ 515	$ 129	$ 524
Regulatory liabilities:				
Asset retirement removal costs	$ —	$ 872	$ —	$ 837
Trojan decommissioning activities	24	4	17	15
Asset retirement obligations	—	48	—	45
Other	25	34	38	31
Total regulatory liabilities	$ 49 *	$ 958	$ 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):

	September 30, 2016	December 31, 2015
Regulatory liabilities—current	$ 49	$ 55
Accrued employee compensation and benefits	45	51
Accrued interest payable	40	25
Accrued dividends payable	29	28
Accrued taxes payable	43	25
Other	64	75
Total accrued expenses and other current liabilities	$ 270	$ 259

Credit Facilities

As of September 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 September 30, 2016, PGE was in compliance with this covenant with a 51.0% debt-to-total capital ratio.

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

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

Under the revolving credit facility, as of September 30, 2016, PGE had no borrowings, commercial paper, or letters of credit issued. As of September 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, $73 million of letters of credit were outstanding as of September 30, 2016. Letters of credit issued are not reflected on the Company’s condensed consolidated balance sheets.

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

Long-term Debt

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 up to $200 million by October 31, 2016. PGE has obtained the following two term loans:

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

The Company has given notice to the financial institutions that it intends to obtain the third term loan in the amount of $25 million on October 31, 2016. 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 1.2% as of September 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 nine months ended September 30, 2016, PGE had the following First Mortgage Bonds (FMBs) long-term debt transactions, all of which occurred in early January 2016:

- Issued $140 million of 2.51% Series FMBs due in 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 September 30,		Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Service cost	$ 4	$ 4	$ 12	$ 13
Interest cost	9	8	25	24
Expected return on plan assets	(10)	(10)	(30)	(30)
Amortization of net actuarial loss	3	5	11	15
Net periodic benefit cost	$ 6	$ 7	$ 18	$ 22

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 September 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 measurement date.

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

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

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. 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 nine month periods ended September 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 September 30, 2016				
	Level 1	Level 2	Level 3	Other(2)	Total
Assets:					
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	$ 2	$ 10	$ —	$ —	$ 12
Corporate credit	—	9	—	—	9
Money market funds measured at NAV(2)	—	—	—	20	20
Non-qualified benefit plan trust: (3)					
Equity securities—domestic	4	—	—	—	4
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	—	2	—	—	2
Natural gas	—	5	—	—	5
	$ 7	$ 26	$ —	$ 23	$ 56
Liabilities from price risk management activities: (1) (4)					
Electricity	$ —	$ 4	$ 139	$ —	$ 143
Natural gas	—	65	21	—	86
	$ —	$ 69	$ 160	$ —	$ 229

(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 measurement date.

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

Equity securities—Equity mutual fund and common stock securities are 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 measurement date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange.

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. 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 September 30, 2016:							
Electricity physical forwards	$ —	$ 139	Discounted cash flow	Electricity forward price (per MWh)	$ 15.58	$ 41.79	$ 29.50
Natural gas financial swaps	—	21	Discounted cash flow	Natural gas forward price (per Decatherm)	1.84	3.23	2.26
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	19.29	33.75	26.78
	$ —	$ 160					
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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Balance as of the beginning of the period	$ 158	$ 168	$ 119	$ 100
Net realized and unrealized losses*	—	15	40	85
Transfers out of Level 3 to Level 2	2	(14)	1	(16)
Balance as of the end of the period	$ 160	$ 169	$ 160	$ 169

* 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 nine months ended September 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 September 30, 2016, the carrying amount of PGE's long-term debt was $2,325 million, net of $11 million of unamortized debt expense, and its estimated aggregate fair value was $2,885 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):

	September 30, 2016	December 31, 2015
Current assets:		
Commodity contracts:		
Electricity	$ 2	$ 7
Natural gas	3	3
Total current derivative assets	5 (1)	10 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	—	—
Natural gas	2	—
Total noncurrent derivative assets	2 (2)	— (2)
Total derivative assets not designated as hedging instruments	$ 7	$ 10
Total derivative assets	$ 7	$ 10
Current liabilities:		
Commodity contracts:		
Electricity	$ 11	$ 36
Natural gas	55	94
Total current derivative liabilities	66	130
Noncurrent liabilities:		
Commodity contracts:		
Electricity	132	97
Natural gas	31	64
Total noncurrent derivative liabilities	163	161
Total derivative liabilities not designated as hedging instruments	$ 229	$ 291
Total derivative liabilities	$ 229	$ 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):

	September 30, 2016		December 31, 2015	
Commodity contracts:				
Electricity	8	MWh	12	MWh
Natural gas	123	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 given counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit. As of September 30, 2016 and December 31, 2015, gross amounts included as Price risk management liabilities subject to master netting agreements were $143 million and $111 million, respectively, for which PGE posted collateral of $15 million as of September 30, 2016, which consisted of $14 million of letters of credit and $1 million of cash, and $14 million as of December 31, 2015, which consisted entirely of letters of credit. As of September 30, 2016, of the gross amounts recognized, $139 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Commodity contracts:				
Electricity	$ 8	$ 7	$ 60	$ 77
Natural Gas	10	35	(14)	79
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 September 30, 2016 and 2015, net losses of $20 million and net losses of $34 million have been offset, respectively. Net losses of $36 million and $150 million have been offset for the nine month periods ended September 30, 2016 and 2015, respectively.

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Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of September 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	$ 8	$ 8	$ 7	$ 109	$ 141
Natural gas	20	41	13	5	2	—	81
Net unrealized loss	$ 23	$ 47	$ 21	$ 13	$ 9	$ 109	$ 222

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

The aggregate fair value of derivative instruments with credit-risk-related contingent features that were in a liability position as of September 30, 2016 was $227 million, for which PGE has posted $36 million in collateral, consisting of $31 million in letters of credit and $5 million in cash. If the credit-risk-related contingent features underlying these agreements were triggered at September 30, 2016, the cash requirement to either post as collateral or settle the instruments immediately would have been $219 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:

	September 30, 2016	December 31, 2015
Assets from price risk management activities:		
Counterparty A	34%	5%
Counterparty B	12	8
Counterparty C	10	8
Counterparty D	7	10%
Counterparty E	2	59%
	65%	90%
Liabilities from price risk management activities:		
Counterparty F	61%	36%
Counterparty C	8	10
Counterparty B	7	10
	76%	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 nine month periods ended September 30, 2016, unvested performance-based restricted stock units and related dividend equivalent rights of approximately 306,000 were excluded from the dilutive calculation because the performance goals had not been met, with 308,000 excluded for the three and nine month periods ended September 30, 2015.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Weighted-average common shares outstanding—basic and diluted	88,921	88,766	88,885	82,633

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NOTE 6: EQUITY

The activity in equity during the nine months ended September 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	133,875	1	—	—	1
Stock-based compensation	—	2	—	—	2
Dividends declared	—	—	—	(84)	(84)
Other comprehensive income	—	—	1	—	1
Net income	—	—	—	132	132
Balances as of September 30, 2016	88,926,626	$ 1,199	$ (7)	$ 1,118	$ 2,310
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	143,833	1	—	—	1
Stock-based compensation	—	3	—	—	3
Dividends declared	—	—	—	(75)	(75)
Net income	—	—	—	121	121
Balances as of September 30, 2015	88,772,172	$ 1,193	$ (7)	$ 1,046	$ 2,232

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

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

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be 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) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, will be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

Carty

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. 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 early October 2016, the bankruptcy court in the Chapter 11 proceeding granted the Company’s motion for relief from stay with respect to the four entities that collectively comprise the Contractor, which allows the Company to bring claims against such entities in the U.S. District Court. On October 21, 2016, PGE filed a complaint in the U.S. District Court for the District of Oregon against Abeinsa for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from Abeinsa in excess of $200 million for: i) costs incurred to complete construction of Carty, settle claims with unpaid contractors and vendors and remove liens; and ii) damages in excess of the construction costs, including a project management fee, liquidated damages under the Construction Agreement, legal fees and costs, damages due to delay of the project, warranty costs, and interest.

On March 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. The Sureties appealed the rulings to the Ninth Circuit Court of Appeals and asked the district court to stay the district court proceedings pending resolution of the appeal. In October 2016, the district court denied the request to stay the proceedings. Briefing on the appeal to the Ninth Circuit has been completed, but no oral argument dates have been set. On October 24, 2016, the Sureties filed a motion with the Ninth Circuit for a stay of PGE's district court proceedings against the Sureties pending appeal. Briefing by the parties will proceed on this motion but no oral argument dates have been set.

Recovery of Capital Costs in Excess of $514 million—Following termination of the Construction Agreement, PGE brought on new contractors and resumed construction. Carty was placed into service on July 29, 2016 and the Company began including its revenue requirement, based on the approved cost of $514 million, in customer prices on August 1. 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 will 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, the Company is incurring 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 that the OPUC delay its review of this deferral request until the Company's claims against the Sureties have been resolved. Until such time, the effects of this higher cost of service are recognized in the Company's results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP. Any amounts approved by the OPUC for recovery under the deferral filing will be recognized in earnings in the period of such approval, however there is no assurance that such recovery would be granted by the OPUC. The Company believes that costs incurred to date and capitalized in Electric utility plant, net in the condensed consolidated balance sheet were prudently incurred. There have been no settlement discussions with regulators related to such costs.

EPA Investigation of Portland Harbor

A 1997 investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site and listed 69 Potentially Responsible Parties (PRPs). PGE was included among the PRPs as it has historically owned or operated property near the river. In 2008, the EPA requested information from various parties, including PGE, concerning additional properties in or near the original segment of the river under investigation as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over 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 LWG has funded the RI and feasibility study (FS) and has stated that it has incurred $114 million in investigation-related costs. The Company anticipates that such costs will ultimately be allocated to PRPs as a part of the allocation process for remediation costs of the EPA's preferred remedy.

The EPA has finalized the FS, along with the RI, and these documents 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 remediate 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. The 90-day public comment period ended September 6, 2016. The Company currently expects the EPA to issue a determination of its preferred remedy in a final ROD in late 2016 or early 2017. However, responsibility for funding and implementing the EPA's selected remedy is not expected to be determined until several years thereafter. Although PGE is participating in a voluntary process for allocation of costs, the Company does not have the ability to reasonably estimate an allocation percentage as significant uncertainties still remain surrounding facts and circumstances that are integral to determining such a percentage, such as, agreement on a final allocation methodology, and data surrounding property specific activities and history of ownership of sites within the Portland Harbor.

Where injuries to natural resources have occurred as a result of releases of hazardous substances, federal and state natural resource trustees may seek to recover for damages at such sites, which are referred to as natural resource damages. As it relates to the Portland Harbor, PGE has been participating in the Portland Harbor Natural Resource Damages assessment (NRDA) process. The EPA does not manage NRDA activities, but provides claims information and coordination support to the Natural Resource Damages (NRD) trustees. Damage assessment activities are typically conducted by a Trustee Council made up of the trustee entities for the site, 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. The NRD trustees will assign initial NRD liability allocations to PRPs, which the Company anticipates will occur in the first half of 2017. 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. It is probable that PGE will share in a portion of these costs. However, the Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of the Portland Harbor site and NRDA, although such costs could be material. 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. The Company is currently in discussions with OPUC Staff and other parties regarding the details of the recovery mechanism and anticipates a final decision in the first quarter of 2017. The mechanism, as proposed, 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.

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 in an order issued October 18, 2016, rejected the California Parties' request for refunds from the respondent, finding that the California Parties had not met their *Mobile-Sierra* burden of proof.

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." Because the remaining respondent previously had stated on the record that it would not pursue ripple claims if it were required to pay refunds pursuant to the additional proceedings described above, the Acting Chief Administrative Law Judge issued an order in February 2016, 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.

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

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 not provide a remedy, the court system may have a role to play. The OSC also ruled that the plaintiffs retained the right to return to the Circuit Court for disposition of whatever issues remained unresolved from the remanded OPUC proceedings. In October 2006, the Circuit Court abated the class actions in response to the ruling of the OSC.

In June 2015, based on a motion filed by PGE, the Circuit Court lifted the abatement and in July 2015, the Circuit Court heard oral argument on the Company's motion for Summary Judgment. Following oral argument on PGE's motion for summary judgment, the plaintiffs moved to amend the complaints. On February 22, 2016, the Circuit Court denied the plaintiff's motion to amend the complaint and on March 16, 2016, the Circuit Court entered a general judgment that granted the Company's motion for summary judgment and dismissed all claims by the plaintiffs. On April 14, 2016, the plaintiffs appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon.

PGE believes that the October 2, 2014 OSC decision and the recent Circuit Court decisions have reduced the risk of a loss to the Company in excess of the amounts previously recorded and discussed above. However, because the class actions remain subject to 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.

Alleged Violation of Environmental Regulations at Colstrip

In 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 sought civil penalties along with 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.

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. On September 6, 2016, the judge entered the consent decree, representing final approval from the Court. Pursuant to the terms of the settlement, all claims alleging 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. 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: 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 September 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, 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, employee, or Company information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and the number of employees approaching retirement;
- new federal, state, and local laws that could have adverse effects on operating results;
- 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 Integrated Resource Plan (IRP), which will address anticipated resource needs over the next 20 years. The areas of focus for the plan, expected to be filed with the OPUC in the fourth quarter 2016, include, among other topics, additional resources needed to meet Oregon’s Renewable Portfolio Standard (RPS) requirements and to replace energy from Boardman, which will 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, which, among other things, increased the renewable energy thresholds under the RPS. For further information on this law, see the *“Legal, Regulatory, and Environmental Matters”* section of this Overview.

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—On July 29, 2016, Carty, a 440 MW natural gas-fired baseload resource in Eastern Oregon, was placed into service. As of September 30, 2016, PGE had $615 million in plant in service related to Carty. 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. For additional details regarding various legal proceedings related to Carty, see Note 7, Contingencies, in the Notes to the Condensed Consolidated Financial Statements.

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, 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 associated with the construction of Carty, as well as operating costs. The price change consisted 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, 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 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.

Capital Requirements and Financing—In total, the Company's 2016 capital expenditures are expected to approximate $614 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 typically experiences its highest average MWh deliveries and retail energy sales during the winter heating season, although deliveries also increase during the summer months, generally resulting from air conditioning demand. Retail customer price changes and customer usage patterns, which can be affected by the economy, also have an effect on revenues while wholesale power availability and price, hydro and wind generation, and fuel costs for thermal and gas plants can also affect income from operations.

Customers and Demand—The 3.4% decrease in retail energy deliveries for the nine months ended September 30, 2016 compared with the nine months ended September 30, 2015 resulted predominantly from a decrease in industrial energy deliveries, although energy deliveries to commercial and, to a lesser extent, residential customers also declined.

The decrease in industrial demand was primarily due to the closure of a customer's large paper manufacturing facility in late 2015 and also reflects declines in metal, solar panel, and transportation equipment manufacturing, offsetting growth from the high tech sector. Additionally, growth in deliveries to high tech customers has slowed relative to the past few years as expansion at a large customer's facility comes to completion.

The decreases in residential and commercial energy deliveries were driven by a mild summer cooling season relative to 2015, the effect of which countered the positive influence of weather in the first quarter. While growth in the average number of residential customers remains strong, the average usage per customer continues to reflect an extended downward trend. Lower commercial deliveries, despite a 1.0% growth in the average number of customers, reflect weakness in electricity usage by small commercial customers as well as reduced irrigation and pumping load to date in 2016 due to the extreme dry conditions that existed in 2015. Energy efficiency continues to impact growth, and conservation and building codes and standards are likely reducing energy deliveries beyond the impact of energy efficiency programs. To the extent average weather adjusted usage per customer varies from expectations established in the latest GRC, the financial impacts to PGE of any such reduction in usage by residential and small commercial customers is partially mitigated by the Company's decoupling mechanism.

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, during which PGE normally experiences considerable load from heating demand, the State of Oregon experienced the warmest average temperatures on record during 2015. Residential energy deliveries, which are weather sensitive, and commercial deliveries, although weather sensitive to a lesser extent, were 8.9%, and 4.0% higher, respectively, in the first quarter 2016 than the first quarter of 2015, as a result of the historic warm weather in early 2015.

Weather negatively impacted the demand for electricity in the second and third quarters of 2016 and, when compared to the prior year, has more than offset the favorable impact that resulted on a comparable basis in the first quarter of 2016. Total heating degree-days on a year-to-date basis, although comparable to 2015, were 22% below historical average. When compared to the prior year, the increase in heating degree days in the first quarter 2016 has been offset by the relative lack thereof in the second and third quarters. Cooling degree-days on a year-to-date basis, all of which occur in the second and third quarters, were 17% above average, but 30% below the 2015 levels.

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

	Nine Months Ended September 30,				
	2016		2015		% Increase (Decrease)in Energy Deliveries
	Average Number of Customers	Retail Energy Deliveries*	Average Number of Customers	Retail Energy Deliveries*	
Residential	751,198	5,278	741,249	5,308	(0.6)%
Commercial (PGE sales only)	106,458	5,148	105,430	5,246	(1.9)%
Direct access	314	403	331	401	0.5 %
Total Commercial	106,772	5,551	105,761	5,647	(1.7)%
Industrial (PGE sales only)	193	2,168	199	2,563	(15.4)%
Direct access	63	907	61	875	3.7 %
Total Industrial	256	3,075	260	3,438	(10.6)%
Total (PGE sales only)	857,849	12,594	846,878	13,117	(4.0)%
Total Direct access	377	1,310	392	1,276	2.7 %
Total	858,226	13,904	847,270	14,393	(3.4)%

* In thousands of MWh.

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 generating plants require varying levels of annual maintenance, during which the respective plants are unavailable to provide power. As a result, the amount of power generated to meet the Company's retail load requirement can vary from period to period. Plant availability, which is affected by both planned and unplanned outages, approximated 94% and 93% during the nine months ended September 30, 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 85% and 94% during the nine months ended September 30, 2016 and 2015, respectively.

During the nine months ended September 30, 2016, the Company's generating plants provided approximately 69% of its retail load requirement compared with 60% in the nine months ended September 30, 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, including the addition of Carty, during 2016 relative to 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 nine months ended September 30, 2016, energy received from these hydro resources increased by 3% compared to the nine months ended September 30, 2015. Energy received from these hydro resources fell below projected levels included in PGE's AUT by 2% and 7% for the nine months ended September 30, 2016 and 2015, respectively, and provided 18% and 16% of the

Company's retail load requirement for the nine months ended September 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 nine months ended September 30, 2016, energy received from these wind generating resources increased 14% compared to the nine months ended September 30, 2015. Energy received from these wind generating resources fell short of that projected in PGE's AUT by 6% for the nine months ended September 30, 2016 and 20% for the nine months ended September 30, 2015, and provided approximately 12% and 10% of the Company's retail load requirement during the nine months ended September 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 $30 million above to $15 million below baseline NVPC, the PCAM provides for 90% of the variance beyond the deadband to be collected from or refunded to customers, respectively, subject to a regulated earnings test.

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

For the nine months ended September 30, 2016, actual NVPC was $3 million below baseline NVPC. Based on forecast data, NVPC for the year ending December 31, 2016 is currently estimated to be below the baseline NVPC, but within the deadband range. Accordingly, no estimated collection from, or refund to, customers is expected under the PCAM for 2016.

For the nine months ended September 30, 2015, actual NVPC was $4 million above 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.

PGE has contractual access to natural gas storage in Mist, Oregon from which it can draw in the event that natural gas supplies are interrupted or if economic factors require its use. The storage facility is owned and operated by a local natural gas company, NW Natural, and may be utilized to provide fuel to PGE's Port Westward Unit 1 and Beaver natural gas-fired generating plants and the Port Westward Unit 2 natural gas-fired flexible capacity generating plant. PGE has entered into a long-term agreement with this gas company to expand the current storage facilities, including the construction of a new 13-mile pipeline, that will be designed to provide no-notice storage services to these PGE generating plants. Pursuant to the agreement, on September 30, 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which the gas company estimates will be completed during the winter of 2018-2019, at a cost of approximately $125 million. For accounting purposes, this long-term storage agreement will be treated as a capital lease.

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

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

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

Oregon Clean Electricity and Coal Transition Plan—The State of Oregon passed Senate Bill 1547, effective March 8, 2016, a law referred to as the Oregon Clean Electricity and Coal Transition Plan (OCEP). The legislation prevents large utilities from including the costs and benefits associated with coal-fired generation in their Oregon retail rates after 2030 (subject to an exception that extends this date until 2035 for the Company's output from the Colstrip 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 renewable adjustment clause mechanism (RAC) filings.

The Company continues to evaluate the potential impacts and is in the process of incorporating the effects of the legislation into its 2016 IRP, which is anticipated to be filed with the OPUC in the fourth quarter of 2016. On October 12, 2016, the Company filed a tariff request with the OPUC seeking approval to incorporate in customer prices on January 1, 2017 the estimated annual $6 million effect of accelerating recovery of the Colstrip facility from 2042 to 2030, as required under the legislation.

Ballot Measure 97—The State of Oregon will have a citizens' initiative, Measure 97, on the November 2016 ballot that, if passed, would impose a minimum tax of 2.5% on Oregon gross receipts on businesses with annual Oregon sales in excess of $25 million, effective January 1, 2017. If the initiative becomes law, it would impact the Company's tax liability, both current and deferred, and could potentially increase the cost to procure goods and services from other companies also impacted by the initiative.

PGE continues to assess these and other potential impacts on the Company's financial position and results of operations, and anticipates that incremental costs associated with the initiative would be recovered through customer prices, though the timing of any price change may not align with the resulting increase in costs.

Clean Power Plan—In August 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 in light of the Supreme Court stay.

The following discussion highlights certain regulatory items that have impacted the Company’s revenues, results of operations, or cash flows for the first three quarters of 2016 compared to the first three quarters 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 reviewed the results of the PCAM for 2015 and on September 6, 2016 issued an Order that no refund to or collection from customers would occur during 2017.

The Company has filed updates to its 2017 AUT filing of expected power costs, most recently September 30, 2016, that would collectively result in a $59 million decrease in NVPC. Pursuant to the schedule established in the proceeding, updates of the forecast will occur through mid-November that could change this estimate. The Company anticipates an OPUC order, which would decide the disposition of the filed stipulation, by early November.

As a result of the recently passed OCEP legislation described above, PGE’s 2017 AUT filing included projected PTCs for the 2017 calendar year. Prior to this legislative change, PGE included forecasts of PTCs only in General Rate Case proceedings. The inclusion of PTCs in the AUT provides for annual forecast updates for these estimated tax credits, thus reducing the risk of regulatory lag in terms of adjusting customer prices. Any adjustment in customer prices resulting from the 2017 AUT, including any change from the treatment of the PTCs, would be expected to occur January 1, 2017.

Renewable Resource Costs—Pursuant to its 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 the RAC 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 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 had filed a request with the OPUC to have the mechanism extended beyond 2016 and on September 26, 2016, the OPUC issued an order granting authorization through 2019. Subject to OPUC approval, 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. Subject to OPUC approval, the $9 million refund recorded in 2015 that resulted from variances between actual weather adjusted use per customer and that projected in the 2015 GRC, is expected to occur over a one year period, which would begin January 1, 2017.

For the nine months ended September 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 GRC, intended primarily to allow recovery of costs associated with the construction and operation of Carty. The net annual revenue requirement increase was implemented in two phases, with the first, a $44 million decrease, effective January 1, 2016. See "Carty" in the Overview section for discussion regarding the second phase as approved within the order, which became effective August 1, 2016.

Integrated Resource Plan—PGE's IRP outlines how the Company proposes to 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, included an "Action Plan" that covered PGE's proposed actions before the end of 2017. The Company continues to make substantial progress on the Action Plan items and has completed several related studies including 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 year 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 (2016 IRP), which it expects to file with the OPUC in mid- November 2016. The 2016 IRP will address additional resources to meet Oregon's Renewable Portfolio Standard (RPS) requirements and replace energy and capacity from Boardman, which will cease coal-fired operations at the end of 2020. Further actions identified through 2021 are expected to offset expiring power purchase agreements and integrate variable energy resources, such as wind or solar generation facilities. The 2016 IRP will also consider the OCEP, which, among other things, increased the RPS requirements for 2025 and future years. For further information on the OCEP, see the *"Legal, Regulatory and Environmental"* section of this Item 2.

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

A draft of the 2016 IRP is available on PGE's website. The recommended Action Plan in the draft IRP encompasses both demand-side and supply-side actions as well as integration through energy storage systems. While the draft IRP could undergo further modifications prior to filing with the OPUC, the current draft specifically recommends: i) the deployment of a minimum of 135 MWa of cost-effective energy efficiency; ii) the pursuit of up to 77 MW of additional demand response; and iii) the addition of approximately 175 MWa in RPS compliant renewable resources, which could include unbundled Renewable Energy Certificates. The current draft also identifies the need for PGE to acquire up to 850 MW of capacity, which includes 375-550 MW of long-term dispatchable resources and up to 400 MW of annual capacity resources.

PGE continues to accept input from stakeholders as it finalizes the 2016 IRP. Acknowledgment of the 2016 IRP is targeted for mid-2017. Upon acknowledgment, PGE will request approval from the OPUC to issue one or more RFPs to acquire capacity and renewable resources through a combination of resource options that could include wind, solar, geothermal, biomass, efficient combined-cycle natural gas fired facilities, and generic capacity facilities such as seasonal contracts, power purchase agreements, energy storage, and combustion turbines. The RFP process will include oversight by an independent evaluator and review by the OPUC.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 was signed into law, and among other things, extended the production tax credit (PTC) through a five year step down, phase out period. In an attempt to capture the full benefit of the PTCs and meet the Company's future RPS requirements and resource needs, the Company filed a petition with the OPUC in May 2016 seeking approval of an accelerated Request for Proposals (RFP) for additional renewable resources.

Based on input from a public comment period, the Commission decided to take no action on whether to approve the RFP. In light of the questions expressed by the OPUC, Staff and other parties, the Company has suspended the RFP, and will continue to identify its resource needs, including renewables, through the IRP process.

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 September 30,				Nine Months Ended September 30,			
	2016		2015		2016		2015	
Revenues, net	$ 484	100%	$ 476	100 %	$ 1,399	100%	$ 1,399	100%
Purchased power and fuel	180	37	181	38	455	33	490	35
Gross margin	304	63	295	62	944	67	909	65
Other operating expenses:								
Generation, transmission and distribution	69	14	64	14	199	14	192	14
Administrative and other	63	13	59	12	185	13	179	13
Depreciation and amortization	79	16	76	16	244	17	227	16
Taxes other than income taxes	29	6	28	6	89	6	86	6
Total other operating expenses	240	50	227	48	717	51	684	49
Income from operations	64	13	68	14	227	16	225	16
Interest expense*	28	6	28	5	82	6	86	6
Other income:								
Allowance for equity funds used during construction	4	1	6	1	19	1	15	1
Miscellaneous income (expense), net	—	—	(2)	—	—	—	—	—
Other income, net	4	1	4	1	19	1	15	1
Income before income tax expense	40	8	44	10	164	12	154	11
Income tax expense	6	1	8	2	32	2	33	2
Net income	$ 34	7%	$ 36	8 %	$ 132	9%	$ 121	9%

* Net of an allowance for borrowed funds used during construction of $2 million and $3 million for the three months ended September 30, 2016 and 2015, respectively, and $10 million and $9 million for the nine months ended September 30, 2016 and 2015.

Net income attributable to PGE was $34 million, or $0.38 per diluted share, for the three months ended September 30, 2016 compared with $36 million, or $0.40 per diluted share, for the three months ended September 30, 2015. The decrease in Net income reflects incremental expenses attributed to Carty beyond those authorized for recovery in customer prices. Wholesale sales, which are a reduction component of NVPC, were $19 million higher, primarily due to higher sales volumes. Actual NVPC was $3 million above the baseline for the third quarter of 2016, while actual NVPC was $6 million above baseline NVPC for the third quarter of 2015. Allowance for equity funds during construction also decreased by $2 million due to lower average CWIP balances. The resulting net income decreases were partially the result of an $11 million decrease in Retail revenues due to 7.6% lower volumes of retail energy delivered resulting in part from mild weather in comparison to the third quarter of 2015.

Net income attributable to PGE was $132 million, or $1.49 per diluted share, for the nine months ended September 30, 2016, compared with $121 million, or $1.47 per diluted share, for the nine months ended September 30, 2015.

The increase in Net income resulted from reduced NVPC as the average variable power cost per MWh declined 8%. NVPC was $3 million below baseline NVPC for the first nine months of 2016, compared to $4 million above the baseline for the first nine months of 2015. Additionally, allowance for equity funds used during construction increased by $4 million in the first nine months of 2016 in comparison to the first nine months of 2015 due to higher average CWIP balances. Higher operating expenses, including additional depreciation expense, contributed to partially offset the higher net income.

Three Months Ended September 30, 2016 Compared with the Three Months Ended September 30, 2015

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

	Three Months Ended September 30,			
	2016		2015	
Revenues [1] (dollars in millions):				
Retail:				
Residential	$ 203	41%	$ 213	45 %
Commercial	170	35	176	37
Industrial	54	11	59	12
Subtotal	427	88	448	94
Other retail revenues, net	1	—	(9)	(2)
Total retail revenues	428	88	439	92
Wholesale revenues	48	10	29	6
Other operating revenues	8	2	8	2
Total revenues	$ 484	100%	$ 476	100 %
Energy deliveries (MWh in thousands):				
Retail:				
Residential	1,618	27%	1,749	31 %
Commercial	1,751	30	1,862	32
Industrial	754	13	871	15
Subtotal	4,123	70	4,482	78
Direct access:				
Commercial	141	2	145	3
Industrial	301	5	312	5
Subtotal	442	7	457	8
Total retail energy deliveries	4,565	77	4,939	86
Wholesale energy deliveries	1,360	23	836	14
Total energy deliveries	5,925	100%	5,775	100 %
Average number of retail customers:				
Residential	753,345	87%	743,371	87 %
Commercial	107,844	13	106,791	13
Industrial	204	—	196	—
Direct access	373	—	389	—
Total	861,766	100%	850,747	100 %

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

Total revenues for the three months ended September 30, 2016 increased $8 million compared to the three months ended September 30, 2015, comprised primarily of a $19 million increase in Wholesale revenues partially offset by an $11 million decrease in Retail revenues.

The change in Retail revenues resulted from the following:

- A $19 million decrease resulting from a $34 million reduction in revenue related to 7.6% lower retail energy deliveries due to unfavorable weather conditions and a decrease in deliveries to commercial and industrial customers, partly offset by an increase of $15 million that resulted from customer price changes. Energy deliveries to residential and commercial customers decreased 7.5% and 5.7%, respectively, due in part to the effects of more moderate weather, and energy deliveries to industrial customers decreased 10.8%, 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; and
- Supplemental tariffs decreased $5 million as a $7 million reduction in collection, which ended in 2015, for certain capital projects was partly offset by increases of $2 million for the combination of property sales gains in 2015 and the timing of the Trojan spent fuel refund to customers; partially offset by
- An $11 million increase resulted from other tariffs including a $9 million increase in estimated collections under the decoupling mechanism.

Total cooling degree-days for the three months ended September 30, 2016 were 31% below the three months ended September 30, 2015 although nearly on par with average. Total heating degree-days for the three months ended September 30, 2016 were 3% above the three months ended September 30, 2015 and equivalent with average.

The following table indicates the number of heating and cooling degree-days for the three months ended September 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.**
July	3	—	9	140	287	163
August	3	—	8	224	235	168
September	72	76	61	30	51	68
Totals for the quarter	78	76	78	394	573	399

Wholesale revenues for the three months ended September 30, 2016 increased $19 million, or 66%, from the three months ended September 30, 2015, and consisted of an $18 million increase related to a 63% increase in wholesale sales volume and a $1 million increase related to a 2% increase in average wholesale price.

Purchased power and fuel expense decreased $1 million, or 1%, for the three months ended September 30, 2016 compared with the three months ended September 30, 2015, and consisted of $6 million related to a 3% decrease in the average variable power cost per MWh, partially offset by $5 million related to a 3% increase in total system load.

The decrease in the average variable power cost to $30.82 per MWh in the three months ended September 30, 2016 from $31.90 per MWh in the three months ended September 30, 2015 was driven by a 32% increase in MWh’s generated by the Company’s natural gas-fired plants which experienced a 5% decrease in average variable power cost which helped to offset a portion of the 4% increase in average variable power cost per MWh for purchased power. The increase in generation from natural gas-fired plants in 2016 in comparison to 2015 is due largely to the Carty facility being placed in service in July 2016.

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 September 30,			
	2016		2015	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	1,418	24%	1,445	26%
Natural gas	2,243	39	1,702	30
Total thermal	3,661	63	3,147	56
Hydro	267	4	267	4
Wind	570	10	568	10
Total generation	4,498	77	3,982	70
Purchased power:				
Term	913	16	1,260	22
Hydro	322	6	326	6
Wind	91	1	88	2
Total purchased power	1,326	23	1,674	30
Total system load	5,824	100%	5,656	100%
Less: wholesale sales	(1,360)		(836)	
Retail load requirement	4,464		4,820	

Energy received from PGE-owned wind generating resources remained consistent in the three months ended September 30, 2016 compared with the same period of 2015 as a result of similar wind conditions. Energy received from these wind generating resources represented 13% and 12% of the Company's retail load requirements for the three months ended September 30, 2016 and 2015, respectively. Due to slightly less favorable hydroelectric conditions, energy received from hydro resources during the three months ended September 30, 2016, from both PGE-owned generating plants and purchased from mid-Columbia projects, decreased 1% compared with the same period of 2015, and represented 13% and 12% of the Company's retail load requirement for the three months ended September 30, 2016 and 2015, respectively.

The following table presents the actual April-to-September 2016 and 2015 runoff at particular points of major rivers relevant to PGE's hydro resources (as a percentage of normal, as measured over the 30-year period from 1981 through 2010):

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

* Volumetric water supply percentages 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 September 30, 2016 decreased $20 million when compared with the three months ended September 30, 2015. The decrease was driven by a 66% increase in wholesale revenues, a 3% decrease in the average variable power cost per MWh, partially offset by a 3% increase in total system load. The increase in wholesale revenues was driven primarily by a 2% increase in the average wholesale sales price, combined with a 63% increase in wholesale sales volume. For the three months ended September 30, 2016, actual NVPC was $3 million above the baseline, while the three months ended September 30, 2015 actual NVPC was $6 million above baseline NVPC.

Generation, transmission and distribution expense increased $5 million, or 8%, in the three months ended September 30, 2016 compared with the three months ended September 30, 2015 driven primarily by $3 million of expense for Carty (placed in service in 2016).

Administrative and other expense increased $4 million, or 7%, in the three months ended September 30, 2016 compared with the three months ended September 30, 2015. The increase was primarily due to a $3 million increase in legal costs related to Carty.

Depreciation and amortization expense increased $3 million in the three months ended September 30, 2016 compared with the three months ended September 30, 2015. The increase was primarily driven by $6 million additional expense due to capital additions, 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.

Other income, net remained flat for the three months ended September 30, 2016 compared with the three months ended September 30, 2015. This was due to a decrease in the allowance for equity funds used during construction resulting from lower average CWIP balances, primarily related to the Carty project, offset by gains on the non-qualified benefit trust.

Income tax expense was $6 million in the three months ended September 30, 2016 compared with $8 million in the three months ended September 30, 2015, with effective tax rates of 15.0% and 18.2%, respectively. The decrease in income tax expense and effective tax rate was primarily due to lower pre-tax income, partially offset by a decrease in production tax credits.

Nine Months Ended September 30, 2016 Compared with the Nine Months Ended September 30, 2015

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

	Nine Months Ended September 30,			
	2016		2015	
Revenues [1] (dollars in millions):				
Retail:				
Residential	$ 648	47%	$ 647	46 %
Commercial	492	35	498	36
Industrial	153	11	172	12
Subtotal	1,293	93	1,317	94
Other retail revenues, net	5	—	(11)	(1)
Total retail revenues	1,298	93	1,306	93
Wholesale revenues	74	5	66	5
Other operating revenues	27	2	27	2
Total revenues	$ 1,399	100%	$ 1,399	100 %
Energy deliveries (MWh in thousands):				
Retail:				
Residential	5,278	32%	5,308	32 %
Commercial	5,148	31	5,246	32
Industrial	2,168	13	2,563	16
Subtotal	12,594	76	13,117	80
Direct access:				
Commercial	403	2	401	
Industrial	907	6	875	
Subtotal	1,310	8	1,276	—
Total retail energy deliveries	13,904	84	14,393	88
Wholesale energy deliveries	2,621	16	1,954	12
Total energy deliveries	16,525	100%	16,347	100 %
Average number of retail customers:				
Residential	751,198	88%	741,249	87 %
Commercial	106,458	12	105,430	13
Industrial	193	—	199	—
Direct access	377	—	392	
Total	858,226	100%	847,270	100 %

(1) Includes revenues from customers who purchase their energy from the Company as well as $22 million in revenues for 2016 and for 2015 from Direct access customers for transmission and delivery charges only.

Total revenues for the nine months ended September 30, 2016 were comparable to the nine months ended September 30, 2015, as an $8 million increase in Wholesale revenues was offset by a similar decrease in Retail revenues.

The change in Retail revenues resulted from the following:

- A $20 million decrease due to a $45 million reduction in volumes as deliveries were 3.4% below prior year levels, partly offset a $25 million increase resulting from higher customer prices; and
- A net $5 million decrease due to changes to a number of additional supplemental tariff adjustments, including a $17 million reduction as a result of the collection for the capital project deferrals that ended in 2015, partly offset by a $9 million increase due to the delay of customer refunds for much of 2016 related to the Trojan spent fuel settlement with the Department of Energy and $3 million in other miscellaneous tariffs; partially offset by
- A $16 million increase in Other revenues primarily as a result of a $9 million increase in the decoupling mechanism combined with various other tariff changes.

Total heating degree-days for the nine months ended September 30, 2016 were comparable to those for the nine months ended September 30, 2015 although 22% below average. Total cooling degree-days for the nine months ended September 30, 2016 were 30% below those for the nine months ended September 30, 2015, although 17% above average.

The following table indicates the number of heating and cooling degree-days for the nine months ended September 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
Third quarter	78	76	78	394	573	399
Year-to-date	2,066	2,070	2,633	548	780	469

Wholesale revenues for the nine months ended September 30, 2016 increased $8 million, or 12%, from the nine months ended September 30, 2015, and consisted of $22 million related to a 34% increase in wholesale sales volume partially offset by $14 million related to a 16% decrease in wholesale prices.

Purchased power and fuel expense decreased $35 million, or 7%, for the nine months ended September 30, 2016 compared with the nine months ended September 30, 2015, and consisted of $40 million related to an 8% decrease in the average variable power cost per MWh, partially offset by $5 million related to a 1% increase in total system load.

The decrease in the average variable power cost to $28.28 per MWh in the nine months ended September 30, 2016 from $30.76 per MWh in the nine months ended September 30, 2015 was driven by a larger portion of purchased power being replaced by a 10% increase in energy deliveries generated from lower cost Company facilities, combined with a 9% decrease in the average variable power cost for purchased power in 2016. The increase in energy deliveries from the Company’s facilities was driven primarily by a 20% increase from natural gas-fired plants due to the addition of Carty in July 2016, combined with a 14% increase in energy deliveries 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:

	Nine Months Ended September 30,			
	2016		2015	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	2,535	16%	2,656	17%
Natural gas	4,017	25	3,356	21
Total thermal	6,552	41	6,012	38
Hydro	1,214	8	1,063	7
Wind	1,559	10	1,371	9
Total generation	9,325	58	8,446	54
Purchased power:				
Term	5,355	33	5,997	38
Hydro	1,160	7	1,239	8
Wind	241	1	241	1
Total purchased power	6,756	42	7,477	46
Total system load	16,081	100%	15,923	100%
Less: wholesale sales	(2,621)		(1,954)	
Retail load requirement	13,460		13,969	

Energy received from PGE-owned wind generating resources increased 14% in the nine months ended September 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 12% and 10% of the Company’s retail load requirements for the nine months ended September 30, 2016 and 2015, respectively. Due to more favorable hydroelectric conditions, energy received from hydro resources during the nine months ended September 30, 2016, from both PGE-owned generating plants and purchased from mid-Columbia projects, increased 3% compared with the same period of 2015, and represented 18% and 16% of the Company’s retail load requirement for the nine months ended September 30, 2016 and 2015, respectively.

Actual NVPC for the nine months ended September 30, 2016 decreased $43 million when compared with the nine months ended September 30, 2015. The decrease was driven by a 12% increase in wholesale revenues, an 8% decrease in the average variable power cost per MWh, partially offset by a 1% increase in total system load. The increase in wholesale revenues was driven primarily by a 34% increase in wholesale sales volume, partially offset by a 16% decrease in the average wholesale sales price. For the nine months ended September 30, 2016 and 2015, actual NVPC was $3 million below and $4 million above baseline NVPC, respectively.

Generation, transmission and distribution expense increased $7 million, or 4%, in the nine months ended September 30, 2016 compared with the nine months ended September 30, 2015 driven primarily by $3 million higher labor costs, $3 million higher service restoration expenses, and $3 million higher information technology expenses, offset by a $5 million decrease due to the timing of the annual planned outage at Boardman.

Administrative and other expense increased $6 million, or 3%, in the nine months ended September 30, 2016 compared with the nine months ended September 30, 2015. The increase was primarily due to $3 million higher legal costs for Carty.

Depreciation and amortization expense increased $17 million in the nine months ended September 30, 2016 compared with the nine months ended September 30, 2015. The increase was primarily driven by $14 million due to capital additions, $7 million due to the temporary discontinuance of amortization of credits for the regulatory liability for the Trojan spent fuel settlement, and $11 million less of amortization credits related to gains on asset sales and other minor items, offset by a $14 million decrease that resulted from the completion in 2015 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 5%, in the nine months ended September 30, 2016 compared with the nine months ended September 30, 2015, driven by a 4% decrease in the average balance of debt outstanding.

Other income, net was $19 million in the nine months ended September 30, 2016 compared with $15 million in the nine months ended September 30, 2015. The change was due to a $4 million increase in the allowance for equity funds used during construction resulting from higher average CWIP balances.

Income tax expense was $32 million in the nine months ended September 30, 2016 compared with $33 million in the nine months ended September 30, 2015, with effective tax rates of 19.5% and 21.4%, respectively. The decrease in income tax expense was driven by an increase in production tax credits, which more than offset the effect of 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)	$ 407	$ 578	$ 427	$ 294	$ 303
Carty	207	2	—	—	—
Total capital expenditures	$ 614 (2)	$ 580	$ 427	$ 294	$ 303
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, $110 million relates to the implementation of the Company's new customer information and meter data management systems. Includes $149 million in 2017 for transmission, distribution, and generation resiliency projects.
(2) 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"* 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):

	Nine Months Ended September 30,	
	2016	**2015**
Cash and cash equivalents, beginning of period	$ 4	$ 127
Net cash provided by (used in):		
Operating activities	497	439
Investing activities	(454)	(377)
Financing activities	41	(97)
Increase (Decrease) in cash and cash equivalents	84	(35)
Cash and cash equivalents, end of period	$ 88	$ 92

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 nine months ended September 30, 2016 increased $58 million when compared with the nine months ended September 30, 2015. Such increase was largely due to an increase in accounts payable, 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 nine months ended September 30, 2016 increased $77 million when compared with the nine months ended September 30, 2015, largely due to the distribution from the Nuclear decommission trust of $50 million and a sales tax refund related to Tucannon River Wind Farm of $23 million that was included for the nine months ended September 30, 2015.

The Company plans to make capital expenditures of approximately $614 million in 2016, including $207 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 nine months ended September 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 $82 million. During the nine months ended September 30, 2015, net cash used in financing activities consisted of the repayment of long-term debt of $442 million and the payment of dividends of $70 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
October 26, 2016	December 27, 2016	January 17, 2017	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 $290 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 September 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 September 30, 2016, PGE had no borrowings, commercial paper outstanding, or letters of credit issued. As of September 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 $73 million were outstanding as of September 30, 2016.

Long-term Debt. During the nine months ended September 30, 2016, PGE had the following long-term debt transactions:

- 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 an unsecured credit agreement with certain financial institutions, under which the Company may obtain three separate term loans in an aggregate principal amount of up to $200 million by October 31, 2016. PGE borrowed $50 million under the agreement on May 4, 2016, and an additional $75 million on June 15, 2016. The Company has given notice to the financial institutions that it intends to obtain the third term loan in the amount of $25 million on October 31, 2016. The loans are due on November 30, 2017.

As of September 30, 2016, total long-term debt outstanding, net of $11 million of unamortized debt expense, was $2,325 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 ratio was 49.3% and 50.7% as of September 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 S&P Global Ratings (S&P), with current credit ratings and outlook as follows:

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

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

As of September 30, 2016, PGE had posted approximately $38 million of collateral with these counterparties, consisting of $8 million in cash and $30 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 September 30, 2016, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade was approximately $86 million, and decreases to approximately $66 million by December 31, 2016 and to $32 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 $160 million at September 30, 2016, and decreases to approximately $118 million by December 31, 2016 and to $72 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 September 30, 2016, under the most restrictive issuance test in the Indenture, the Company could have issued up to approximately $1,163 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 September 30, 2016, the Company's debt-to-total capital ratio, as calculated under the credit agreement, was 51.0%.

Off-Balance Sheet Arrangements

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

Contractual Obligations

PGE's contractual obligations for 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. For such obligations, there have been no material changes outside the ordinary course of business, as of September 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 September 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 periods ended March 31, 2016 and June 30, 2016, filed with the SEC on April 29, 2016 and August 3, 2016, respectively.

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. On September 6, 2016, the judge entered the consent decree, representing final approval from the Court.

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

On July 27, 2016, the judge denied the Sureties’ motion to stay the case in favor of a pending ICC Arbitration and granted PGE’s motion for an injunction prohibiting the Sureties from pursuing any Performance Bond claims in the ICC Arbitration. The Sureties appealed the rulings to the Ninth Circuit Court of Appeals and asked the district court to stay the district court proceedings pending resolution of the appeal. In October 2016, the district court denied the request to stay the proceedings. Briefing on the merits of the appeal to the Ninth Circuit has been completed, but no oral argument dates have been set. On October 24, 2016, the Sureties filed a motion with the Ninth Circuit for a stay of PGE’s district court proceedings against the Sureties pending the Sureties’ appeal to the Ninth Circuit. Briefing by the parties will proceed on this motion but no oral argument dates have been set. For additional information on this matter, see Note 7, Contingencies, in the Notes to the Condensed Consolidated Financial Statements.

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

On October 21, 2016, PGE filed a complaint in the U.S. District Court of the District of Oregon against Abeinsa for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from Abeinsa in excess of $200 million for: i) costs incurred to complete construction of Carty, settle claims with unpaid contractors and vendors and remove liens; and ii) damages in excess of the construction costs, including a project management fee, liquidated damages under the Construction Agreement, legal fees and costs, damages due to delay of the project, warranty costs, and interest.

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:	October 27, 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:	October 27, 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:	October 27, 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 September 30, 2016, as filed with the Securities and Exchange Commission on October 28, 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: October 27, 2016	Date: October 27, 2016