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

FORM 10-Q

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

For the quarterly period ended **June 30, 2014**

or

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

For the transition period from ____________________ to ____________________

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

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. [x] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). [x] Yes [ ] No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

Number of shares of common stock outstanding as of July 24, 2014 is 78,203,099 shares.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2014

TABLE OF CONTENTS

Table of Contents

DEFINITIONS

The following abbreviations and acronyms are used throughout this document:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
AUT	Annual Power Cost Update Tariff
Biglow Canyon	Biglow Canyon wind farm
Carty	Carty Generating Station natural gas-fired generating plant
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
CWIP	Construction work-in-progress
EFSA	Equity forward sale agreement
EPA	United States Environmental Protection Agency
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMBs	First Mortgage Bonds
IRP	Integrated Resource Plan
kV	Kilovolt = one thousand volts of electricity
Moody's	Moody's Investors Service
MW	Megawatts
MWh	Megawatt hours
NVPC	Net Variable Power Costs
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PW2	Port Westward Unit 2 natural gas-fired generating plant
S&P	Standard and Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Tucannon River	Tucannon River wind farm
Trojan	Trojan nuclear power plant

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues, net	$ 423	$ 403	$ 916	$ 876
Operating expenses:				
Purchased power and fuel	142	156	326	348
Production and distribution	67	64	121	115
Cascade Crossing transmission project	—	52	—	52
Administrative and other	56	55	110	109
Depreciation and amortization	73	62	148	124
Taxes other than income taxes	27	25	55	52
Total operating expenses	365	414	760	800
Income (loss) from operations	58	(11)	156	76
Interest expense	23	25	48	50
Other income:				
Allowance for equity funds used during construction	9	2	15	4
Miscellaneous income, net	1	1	—	2
Other income, net	10	3	15	6
Income (loss) before income tax expense (benefit)	45	(33)	123	32
Income tax expense (benefit)	10	(11)	30	6
Net income (loss) and Comprehensive income (loss)	35	(22)	93	26
Less: net loss attributable to noncontrolling interests	—	—	—	(1)
Net income (loss) and Comprehensive income (loss)attributable to Portland General Electric Company	$ 35	$ (22)	$ 93	$ 27
Weighted-average shares outstanding (in thousands):				
Basic	78,183	75,935	78,154	75,772
Diluted	80,051	75,935	79,742	75,893
Earnings (loss) per share:				
Basic	$ 0.44	$ (0.29)	$ 1.19	$ 0.36
Diluted	$ 0.43	$ (0.29)	$ 1.16	$ 0.36
Dividends declared per common share	$ 0.280	$ 0.275	$ 0.555	$ 0.545

See accompanying notes to condensed consolidated financial statements.

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

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 97	$ 107
Accounts receivable, net	121	146
Unbilled revenues	74	104
Inventories	85	65
Regulatory assets—current	38	66
Other current assets	98	103
Total current assets	**513**	**591**
Electric utility plant, net	5,324	4,880
Regulatory assets—noncurrent	399	464
Nuclear decommissioning trust	83	82
Non-qualified benefit plan trust	33	35
Other noncurrent assets	47	49
Total assets	**$ 6,399**	**$ 6,101**

See accompanying notes to condensed consolidated financial statements.

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

	June 30, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 181	$ 173
Liabilities from price risk management activities—current	32	49
Current portion of long-term debt	70	—
Accrued expenses and other current liabilities	174	171
Total current liabilities	**457**	**393**
Long-term debt, net of current portion	2,071	1,916
Regulatory liabilities—noncurrent	913	865
Deferred income taxes	613	586
Unfunded status of pension and postretirement plans	160	154
Non-qualified benefit plan liabilities	101	101
Asset retirement obligations	105	100
Liabilities from price risk management activities—noncurrent	83	141
Other noncurrent liabilities	24	25
Total liabilities	**4,527**	**4,281**
Commitments and contingencies (see notes)		
Equity:		
Portland General Electric Company shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of June 30, 2014 and December 31, 2013	—	—
Common stock, no par value, 160,000,000 shares authorized; 78,202,241 and 78,085,559 shares issued and outstanding as of June 30, 2014 and December 31, 2013, respectively	914	911
Accumulated other comprehensive loss	(5)	(5)
Retained earnings	962	913
Total Portland General Electric Company shareholders' equity	1,871	1,819
Noncontrolling interests' equity	1	1
Total equity	**1,872**	**1,820**
Total liabilities and equity	**$ 6,399**	**$ 6,101**

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30,	
	2014	**2013**
Cash flows from operating activities:		
Net income	$ 93	$ 26
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	148	124
Cascade Crossing transmission project	—	52
Decrease in net liabilities from price risk management activities	(84)	(16)
Regulatory deferrals—price risk management activities	84	16
Deferred income taxes	20	(1)
Pension and other postretirement benefits	17	20
Allowance for equity funds used during construction	(15)	(4)
Regulatory deferral of settled derivative instruments	6	10
Decoupling mechanism deferrals, net of amortization	(3)	(5)
Other non-cash income and expenses, net	12	10
Changes in working capital:		
Decrease in accounts receivable and unbilled revenues	55	39
Decrease in margin deposits, net	7	12
Decrease in accounts payable and accrued liabilities	(29)	(13)
Other working capital items, net	(14)	11
Cash received to be returned to customers pursuant to the Residential Exchange Program	14	1
Other, net	(9)	(3)
Net cash provided by operating activities	**302**	**279**
Cash flows from investing activities:		
Capital expenditures	(501)	(260)
Sales of nuclear decommissioning trust securities	9	14
Purchases of nuclear decommissioning trust securities	(10)	(15)
Proceeds from sale of property	4	—
Other, net	4	2
Net cash used in investing activities	**(494)**	**(259)**

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30,	
	2014	**2013**
Cash flows from financing activities:		
Proceeds from issuance of long-term debt	$ 225	$ 150
Payments on long-term debt	—	(50)
Proceeds from issuance of common stock, net of issuance costs	—	47
Borrowings on short-term debt	—	35
Payments on short-term debt	—	(35)
Maturities of commercial paper, net	—	(17)
Dividends paid	(43)	(41)
Debt issuance costs	—	(2)
Net cash provided by financing activities	**182**	**87**
Change in cash and cash equivalents	(10)	107
Cash and cash equivalents, beginning of period	107	12
Cash and cash equivalents, end of period	**$ 97**	**$ 119**
Supplemental cash flow information is as follows:		
Cash paid for interest, net of amounts capitalized	$ 45	$ 45
Cash paid for income taxes	11	6
Non-cash investing and financing activities:		
Accrued dividends payable	23	21
Accrued capital additions	105	34
Preliminary engineering costs transferred to Construction work-in-progress from Other noncurrent assets	—	9

See accompanying notes to condensed consolidated financial statements.

NOTE 1: BASIS OF PRESENTATION

Nature of Business

Portland General Electric Company (PGE or the Company) is a single, vertically integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE's corporate headquarters are located in Portland, Oregon and its approximately 4,000 square mile, state-approved service area allocation is located entirely within the state of Oregon, encompassing 52 incorporated cities, of which Portland and Salem are the largest. As of June 30, 2014, PGE served 841,930 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% 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 2014 presentation, PGE has reclassified Margin deposits of $9 million with Other current assets in the condensed consolidated balance sheet as of December 31, 2013. In addition, the Company has separately presented Cash received to be returned to customers pursuant to the Residential Exchange Program of $1 million from Other, net and reclassified Power cost deferrals, net of amortization of $3 million to Other non-cash income and expenses, net in the operating activities section of the condensed consolidated statement of cash flows for the six months ended June 30, 2013.

The financial information included herein for the three and six month periods ended June 30, 2014 and 2013 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 results of operations and comprehensive income, and condensed consolidated cash flows of the Company for these interim periods. 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. The financial information as of December 31, 2013 is derived from the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2013, included in Item 8 of PGE's Annual Report on Form 10-K, filed with the SEC on February 14, 2014, which should be read in conjunction with such condensed consolidated financial statements.

Comprehensive Income

PGE had no material components of other comprehensive income to report for the three and six month periods ended June 30, 2014 and 2013.

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.

Customer Billing Matter

In May 2013, PGE discovered that it had over-billed an industrial customer during a period of several years as a result of a meter configuration error. An analysis of the data determined that the Company's revenues were overstated by approximately $3 million in 2012 and in 2011, $2 million in 2010, and $1 million in 2009. PGE believes the customer billing error is not material to any annual reporting period. The Company corrected this matter in the second quarter of 2013 as an out of period adjustment, and recorded, as a reduction to Revenues, net, a refund to the customer in the amount of $9 million.

Recent Accounting Pronouncement

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 is January 1, 2017 for the Company, with early adoption prohibited. The impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows of the adoption of ASU 2014-09 is not known at this time.

NOTE 2: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $7 million and $6 million as of June 30, 2014 and December 31, 2013, respectively.

The activity in the allowance for uncollectible accounts is as follows (in millions):

	Six Months Ended June 30,	
	2014	**2013**
Balance as of beginning of period	$ 6	$ 5
Provision, net	4	3
Amounts written off, less recoveries	(3)	(3)
Balance as of end of period	$ 7	$ 5

Inventories

PGE inventories, which are recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance, and capital activities and fuel for use in generating plants. Fuel inventories include natural gas, coal, and oil. The Company assesses the realizability of inventory for purposes of determining that inventory is recorded at the lower of average cost or market.

Other Current Assets

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

	June 30, 2014	December 31, 2013
Current deferred income tax asset	$ 43	$ 42
Prepaid expenses	32	38
Assets from price risk management activities	18	13
Margin deposits	2	9
Other	3	1
Other current assets	$ 98	$ 103

Electric Utility Plant, Net

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

	June 30, 2014	December 31, 2013
Electric utility plant	$ 7,213	$ 7,095
Construction work-in-progress	926	508
Total cost	8,139	7,603
Less: accumulated depreciation and amortization	(2,815)	(2,723)
Electric utility plant, net	$ 5,324	$ 4,880

Accumulated depreciation and amortization in the table above includes accumulated amortization related to intangible assets of $182 million and $170 million as of June 30, 2014 and December 31, 2013, respectively. Amortization expense related to intangible assets was $6 million for the three months ended June 30, 2014 and 2013, and $12 million and $11 million for the six months ended June 30, 2014 and 2013, respectively. The Company’s intangible assets primarily consist of computer software development and hydro licensing costs.

During the second quarter of 2013, PGE charged to expense $52 million of costs previously included in construction work-in-progress (CWIP) related to the Cascade Crossing Transmission Project (Cascade Crossing), which was originally proposed as a 215-mile, 500 kV transmission project between Boardman, Oregon and Salem, Oregon. Based on an updated forecast of demand and future transmission capacity in the region, PGE determined in the second quarter of 2013 that the original projections of transmission capacity limitations contemplated in the Company’s 2009 Integrated Resource Plan, as acknowledged by the Public Utility Commission of Oregon (OPUC), were not likely to fully materialize. As a result, PGE and Bonneville Power Administration (BPA) worked toward refining the scope of the project and executed a non-binding memorandum of understanding (MOU) in May 2013. In connection with the MOU, the parties explored a new option under which BPA could provide PGE with ownership of approximately 1,500 MW of transmission capacity rights. As a result of the changed conditions reflected in the MOU, PGE also suspended permitting and development of Cascade Crossing and charged the capitalized costs related to Cascade Crossing to expense in the second quarter of 2013. In October 2013, the parties determined that they would not be able to reach an agreement on the financial terms for the proposed ownership of transmission capacity rights and, therefore, agreed to discontinue discussions on this option. The Company determined that, under conditions at that time, the best option for meeting its transmission needs is to continue to acquire transmission service offered under BPA's Open Access Transmission Tariff. PGE has determined that it will not seek recovery of these costs.

Regulatory Assets and Liabilities

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

	June 30, 2014		December 31, 2013	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Price risk management	$ 14	$ 78	$ 36	$ 140
Pension and other postretirement plans	—	185	—	194
Deferred income taxes	—	81	—	76
Deferred broker settlements	7	—	12	1
Debt reacquisition costs	—	16	—	17
Deferred capital projects	8	19	16	18
Other	9	20	2	18
Total regulatory assets	$ 38	$ 399	$ 66	$ 464
Regulatory liabilities:				
Asset retirement removal costs	$ —	$ 776	$ —	$ 747
Trojan decommissioning activities	—	43	—	41
Asset retirement obligations	—	39	—	39
Other	5	55	1	38
Total regulatory liabilities	$ 5 *	$ 913	$ 1 *	$ 865

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

Accrued Expenses and Other Current Liabilities

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

	June 30, 2014	December 31, 2013
Accrued employee compensation and benefits	$ 42	$ 46
Accrued interest payable	23	23
Accrued dividends payable	23	22
Accrued taxes payable	19	21
Regulatory liabilities—current	5	1
Other	62	58
Total accrued expenses and other current liabilities	$ 174	$ 171

Credit Facilities

PGE has the following unsecured revolving credit facilities as of June 30, 2014:

- A $400 million syndicated credit facility, which is scheduled to expire in November 2018; and
- A $300 million syndicated credit facility, which is scheduled to expire in December 2017.

Pursuant to the terms of the agreements, both revolving credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings, and also 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. Both revolving credit facilities contain provisions for two, one-year extensions that are subject to approval by the banks, require annual fees based on PGE's unsecured credit ratings, and contain customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreements, to 65% of total capitalization. As of June 30, 2014, PGE was in compliance with this covenant with a 53.4% debt to total capital ratio.

PGE 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 facilities.

Pursuant to an order issued by the Federal Energy Regulatory Commission (FERC), the Company is authorized to issue short-term debt up to $900 million through February 6, 2016. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

PGE classifies borrowings under the revolving credit facilities and outstanding commercial paper as Short-term debt on the condensed consolidated balance sheets. As of June 30, 2014, PGE had no borrowings outstanding under the revolving credit facilities, no commercial paper outstanding, and $9 million of letters of credit issued. As of June 30, 2014, the aggregate available capacity under the credit facilities was $691 million.

In addition, the Company has two $30 million letter of credit facilities, which are scheduled to terminate in September and October 2014. As of June 30, 2014, PGE had issued $54 million of letters of credit under these facilities, with an aggregate available capacity of $6 million.

Long-term Debt

In May 2014, PGE entered into an unsecured credit agreement with certain financial institutions, under which the Company may obtain four separate term loans in an aggregate principal amount of $305 million. During the second quarter of 2014, PGE obtained the following three term loans:

- $75 million on May 12, 2014;
- $75 million on June 2, 2014; and
- $75 million on June 30, 2014.

The Company obtained the fourth term loan in the amount of $80 million on July 21, 2014. 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 70 basis points (approximately 0.9% as of June 30, 2014), with no other fees.

The credit agreement expires October 30, 2015, 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.

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

Additionally, in May 2014, PGE entered into a bond purchase agreement with certain institutional buyers (Buyers) under which the Company agreed to sell to the Buyers, in three tranches, an aggregate principal amount of $280 million of First Mortgage Bonds (FMBs) as follows:

- On or about August 15, 2014, $100 million of 4.39% Series FMBs due 2045;
- On or about October 15, 2014, $100 million of 4.44% Series FMBs due 2046; and
- On or about November 17, 2014, $80 million of 3.51% Series FMBs due 2024.

Pension and Other Postretirement Benefits

Components of net periodic benefit cost are as follows (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2014	2013	2014	2013	2014	2013
Three Months Ended June 30:						
Service cost	$ 3	$ 4	$ 1	$ —	$ —	$ —
Interest cost	8	8	1	1	1	1
Expected return on plan assets	(10)	(10)	(1)	(1)	—	—
Amortization of prior service cost	—	—	1	1	—	—
Amortization of net actuarial loss	5	6	—	—	—	—
Net periodic benefit cost	$ 6	$ 8	$ 2	$ 1	$ 1	$ 1
Six Months Ended June 30:						
Service cost	$ 7	$ 8	$ 1	$ 1	$ —	$ —
Interest cost	17	16	2	2	1	1
Expected return on plan assets	(20)	(20)	(1)	(1)	—	—
Amortization of prior service cost	—	—	1	1	—	—
Amortization of net actuarial loss	9	12	—	—	—	—
Net periodic benefit cost	$ 13	$ 16	$ 3	$ 3	$ 1	$ 1

NOTE 3: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company’s condensed consolidated balance sheets, for which it is practicable to estimate fair value as of June 30, 2014 and December 31, 2013, and then classifies these financial assets and liabilities based on a fair value hierarchy. The fair value hierarchy is used to prioritize the inputs to the valuation techniques used to measure fair value. These three levels and application to the Company are discussed below.

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

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

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

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the three and six month periods ended June 30, 2014 and 2013, except those transfers from Level 3 to Level 2 presented in this note.

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

	As of June 30, 2014			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust: (1)				
Money market funds	$ —	$ 59	$ —	$ 59
Debt securities:				
Domestic government	8	6	—	14
Corporate credit	—	10	—	10
Non-qualified benefit plan trust: (2)				
Equity securities—domestic	4	2	—	6
Debt securities—domestic government	1	—	—	1
Assets from price risk management activities: (1) (3)				
Electricity	—	8	—	8
Natural gas	—	12	3	15
	$ 13	$ 97	$ 3	$ 113
Liabilities—Liabilities from price risk management activities: (1) (3)				
Electricity	$ —	$ 4	$ 80	$ 84
Natural gas	—	19	12	31
	$ —	$ 23	$ 92	$ 115

(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) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(3) For further information, see Note 4, Price Risk Management.

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

	As of December 31, 2013			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust: [1]				
Money market funds	$ —	$ 59	$ —	$ 59
Debt securities:				
Domestic government	6	8	—	14
Corporate credit	—	9	—	9
Non-qualified benefit plan trust: [2]				
Equity securities:				
Domestic	4	3	—	7
International	1	—	—	1
Debt securities—domestic government	1	—	—	1
Assets from price risk management activities: [1] [3]				
Electricity	—	9	1	10
Natural gas	—	4	—	4
	$ 12	$ 92	$ 1	$ 105
Liabilities — Liabilities from price risk management activities: [1] [3]				
Electricity	$ —	$ 10	$ 117	$ 127
Natural gas	—	40	23	63
	$ —	$ 50	$ 140	$ 190

(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) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(3) 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:

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 classified as Level 2 in the fair value hierarchy as the securities are traded in active markets of similar securities but are not directly valued using quoted market prices.

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

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

Equity securities—Equity mutual fund and common stock securities are primarily classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the reporting date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange. Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 in the fair value hierarchy as pricing inputs are directly or indirectly observable in the marketplace.

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 consist of 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 forwards, futures and swaps.

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

Commodity Contracts	Fair Value		Valuation Technique	Significant Unobservable Input	Price per Unit		
	Assets	Liabilities			Low	High	Weighted Average
	(in millions)						
As of June 30, 2014:							
Electricity physical forward	$ —	$ 69	Discounted cash flow	Electricity forward price (per MWh)	$ 11.85	$ 98.71	$ 42.61
Natural gas financial swaps	3	12	Discounted cash flow	Natural gas forward price (per Decatherm)	3.41	5.52	4.03
Electricity financial futures	—	11	Discounted cash flow	Electricity forward price (per MWh)	11.92	47.53	39.87
	$ 3	$ 92					
As of December 31, 2013:							
Electricity physical forward	$ —	$ 103	Discounted cash flow	Electricity forward price (per MWh)	$ 9.63	$ 77.95	$ 40.18
Natural gas financial swaps	—	23	Discounted cash flow	Natural gas forward price (per Decatherm)	3.16	4.49	3.71
Electricity financial futures	1	14	Discounted cash flow	Electricity forward price (per MWh)	9.63	46.07	33.01
	$ 1	$ 140					

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 market’s bid-ask spread 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 aggregated 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. This process includes analytical review of changes in commodity prices as well as procedures to analyze and identify the reasons for the changes over specific reporting periods.

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Balance as of the beginning of the period	$ 131	$ 45	$ 139	$ 16
Net realized and unrealized (gains) losses*	(44)	11	(55)	15
Purchases	—	—	—	25
Transfers out of Level 3 to Level 2	2	—	5	—
Balance as of the end of the period	$ 89	$ 56	$ 89	$ 56

* Contains nominal amounts of realized losses. Both realized and unrealized (gains) losses are recorded in Purchased power and fuel expense in the condensed consolidated statements of operations of which the unrealized portion is fully offset by the effects of regulatory accounting until settlement of the underlying transactions.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. During the three and six month periods ended June 30, 2014 and 2013, there were no 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 financial 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 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 is classified as Level 3 fair value measurement and is estimated based on the terms of the loans and the Company's creditworthiness. These significant unobservable inputs to the Level 3 fair value measurement include the interest rate and the length of the loan. The estimated fair value of the Company's unsecured term bank loans approximates their carrying value.

As of June 30, 2014, the carrying amount of PGE's long-term debt was $2,141 million and its estimated aggregate fair value was $2,408 million, consisting of $2,183 million and $225 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy. As of December 31, 2013, the carrying amount of PGE's long-term debt was $1,916 million and its estimated aggregate fair value was $2,074 million, all 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, manage risk, and administer its existing long-term wholesale contracts. Such activities include fuel and power purchases and sales 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.

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 for electricity, natural gas, oil, and foreign currency, which are recorded at fair value on the condensed consolidated balance sheets, with changes in fair value recorded in the condensed consolidated statements of operations. In accordance with the ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer the gains and losses from derivative instruments until settlement of the associated derivative instrument. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. The Company does not engage in trading activities for non-retail purposes.

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

	June 30, 2014	December 31, 2013
Current assets:		
Commodity contracts:		
Electricity	$ 8	$ 9
Natural gas	10	4
Total current derivative assets	18 (1)	13 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	—	1
Natural gas	5	—
Total noncurrent derivative assets	5 (2)	1 (2)
Total derivative assets not designated as hedging instruments	$ 23	$ 14
Total derivative assets	$ 23	$ 14
Current liabilities:		
Commodity contracts:		
Electricity	$ 18	$ 20
Natural gas	14	29
Total current derivative liabilities	32	49
Noncurrent liabilities:		
Commodity contracts:		
Electricity	66	107
Natural gas	17	34
Total noncurrent derivative liabilities	83	141
Total derivative liabilities not designated as hedging instruments	$ 115	$ 190
Total derivative liabilities	$ 115	$ 190

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

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

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

	June 30, 2014		December 31, 2013	
Commodity contracts:				
Electricity	18	MWh	14	MWh
Natural gas	110	Decatherms	106	Decatherms
Foreign currency	$ 9	Canadian	$ 7	Canadian

PGE has elected to report gross on the condensed consolidated balance sheets the positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement. In the case of default on, or termination of, any contract under the master netting arrangements, these agreements provide for the net settlement of all related contractual obligations with a counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit, which are excluded from the offsetting table presented below.

Information related to Price risk management assets and liabilities subject to master netting agreements is as follows (in millions):

	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Gross Amounts Not Offset in Condensed Consolidated Balance Sheets		Net Amount
				Derivatives	Cash Collateral(1)	
As of June 30, 2014:						
Assets:						
Commodity contracts:						
Electricity(2)	$ 1	$ —	$ 1	$ (1)	$ —	$ —
Natural gas(2)	1	—	1	(1)	—	—
	$ 2	$ —	$ 2	$ (2)	$ —	$ —
Liabilities:						
Commodity contracts:						
Electricity(2)	$ 60	$ —	$ 60	$ (60)	$ —	$ —
Natural gas(2)	1	—	1	(1)	—	—
	$ 61	$ —	$ 61	$ (61)	$ —	$ —
As of December 31, 2013:						
Liabilities:						
Commodity contracts:						
Electricity(2)	$ 91	$ —	$ 91	$ (91)	$ —	$ —
Natural gas(2)	1	—	1	(1)	—	—
	$ 92	$ —	$ 92	$ (92)	$ —	$ —

(1) As of June 30, 2014 and December 31, 2013, PGE had posted collateral in the amount of $10 million and $7 million, respectively, which consisted entirely of letters of credit.
(2) Included in Liabilities from price risk management activities—current and Liabilities from price risk management activities—noncurrent.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Commodity contracts:				
Electricity	$ (38)	$ 10	$ (29)	$ 18
Natural Gas	(6)	28	(42)	20

Net unrealized and certain net realized (gains) losses presented in the preceding table are offset within the condensed consolidated statements of operations by the effects of regulatory accounting. Of the net (gains) losses recognized in Net income for the three months ended June 30, 2014 and 2013, net losses of $52 million and $56 million, respectively, have been offset. Net losses of $64 million and $59 million, respectively, have been offset for the six months ended June 30, 2014 and 2013, respectively.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of June 30, 2014 related to PGE’s derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2014	2015	2016	2017	2018	Thereafter	Total
Commodity contracts:							
Electricity	$ 2	$ 17	$ 10	$ 4	$ 4	$ 39	$ 76
Natural gas	4	3	8	2	(1)	—	16
Net unrealized loss	$ 6	$ 20	$ 18	$ 6	$ 3	$ 39	$ 92

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

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of June 30, 2014 was $112 million, for which PGE has posted $18 million in collateral, consisting primarily of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at June 30, 2014, the cash requirement to either post as collateral or settle the instruments immediately would have been $98 million. As of June 30, 2014, PGE has posted an immaterial amount of cash collateral, which is classified as Margin deposits included in Other current assets on the Company’s condensed consolidated balance sheet, for derivative instruments with no credit-risk related contingent features.

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

	June 30, 2014	December 31, 2013
Assets from price risk management activities:		
Counterparty A	30%	53%
Counterparty B	19	5
Counterparty C	11	6
	60%	64%
Liabilities from price risk management activities:		
Counterparty D	50%	43%
Counterparty E	10	11
	60%	54%

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 is computed based on the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the period using the treasury stock method. Potential common shares consist of: i) employee stock purchase plan shares; ii) unvested time-based and performance-based restricted stock units, along with associated dividend equivalent rights; and iii) shares issuable pursuant to an equity forward sale agreement (EFSA). See Note 6, Equity, for additional information on the EFSA and its impact on earnings per share. Unvested performance-based restricted stock units and associated dividend equivalent rights are included in dilutive potential common shares only after the performance criteria have been met. For the three and six month periods ended June 30, 2014 and 2013, unvested performance-based restricted stock units and associated dividend equivalent rights of approximately 365,000 and 435,000, respectively, were excluded from the dilutive calculation because the performance goals had not been met.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Weighted-average common shares outstanding—basic	78,183	75,935	78,154	75,772
Dilutive effect of potential common shares	1,868	—	1,588	121
Weighted-average common shares outstanding—diluted	80,051	75,935	79,742	75,893

Due to PGE's net loss position for the three months ended June 30, 2013, shares of approximately 228,000 related to shares issuable pursuant to the EFSA and unvested restricted stock units shares were excluded from the diluted weighted average common shares outstanding as their effect would have been anti-dilutive.

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

NOTE 6: EQUITY

The activity in equity during the six months ended June 30, 2014 and 2013 is as follows (dollars in millions):

	Portland General Electric Company Shareholders' Equity				Noncontrolling Interests' Equity
	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	
	Shares	Amount			
Balances as of December 31, 2013	78,085,559	$ 911	$ (5)	$ 913	$ 1
Issuances of shares pursuant to equity-based plans	116,682	—	—	—	—
Stock-based compensation	—	3	—	—	—
Dividends declared	—	—	—	(44)	—
Net income	—	—	—	93	—
Balances as of June 30, 2014	78,202,241	$ 914	$ (5)	$ 962	$ 1
Balances as of December 31, 2012	75,556,272	$ 841	$ (6)	$ 893	$ 2
Issuances of common stock, net of issuance costs of $2	1,665,000	47	—	—	—
Issuances of shares pursuant to equity-based plans	141,186	—	—	—	—
Stock-based compensation	—	1	—	—	—
Dividends declared	—	—	—	(42)	—
Net income (loss)	—	—	—	27	(1)
Balances as of June 30, 2013	77,362,458	$ 889	$ (6)	$ 878	$ 1

In connection with a public offering of shares of its common stock in 2013, PGE entered into an EFSA. Pursuant to the terms of the EFSA, a forward counterparty borrowed 11,100,000 shares of PGE's common stock from third parties in the open market and sold the shares to a group of underwriters for $29.50 per share, less an underwriting discount equal to $0.96 per share. The underwriters then sold the shares in a public offering. PGE receives proceeds from the sale of common stock when the EFSA is physically settled (described below), and at that time PGE records the proceeds in equity.

Under the terms of the EFSA, PGE may elect to settle the equity forward transactions by means of: i) physical; ii) cash; or iii) net share settlement, in whole or in part, at any time on or prior to June 11, 2015, except in specified circumstances or events that would require physical settlement. To the extent that the transactions are physically settled, PGE is required to issue and deliver shares of PGE common stock to the forward counterparty at the then applicable forward sale price. The forward sale price was initially determined to be $29.50 per share at the time the EFSA was entered into, and the amount of cash to be received by PGE upon physical settlement of the EFSA is subject to certain adjustments in accordance with the terms of the EFSA.

The use of the EFSA substantially eliminates future equity market price risk by fixing the common stock offering sales price under the then existing market conditions, while mitigating immediate share dilution resulting from the offering by postponing the actual issuance of common stock until such funds are needed in accordance with the Company's capital requirements. The EFSA had no initial fair value since it was entered into at the then market price of the common stock. PGE concluded that the EFSA was an equity instrument and that it does not qualify as a derivative because the EFSA was indexed to the Company's stock. PGE anticipates settling the EFSA through physical settlement on or before June 11, 2015.

At June 30, 2014, the Company could have physically settled the EFSA by delivering 10,400,000 shares to the forward counterparty in exchange for cash of $281 million. In addition, at June 30, 2014, the Company could have elected to make a cash settlement by paying approximately $79 million, or a net share settlement by delivering approximately 2,287,000 shares of common stock. To the extent that PGE makes a cash or net share settlement, the Company would receive no additional proceeds from the public offering.

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

NOTE 7: CONTINGENCIES

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

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

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

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

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

Trojan Investment Recovery

Regulatory Proceedings. 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 1998, the Oregon Court of Appeals upheld the OPUC's order authorizing PGE's recovery of the Trojan investment, but held that the OPUC did not have the authority to allow the Company to recover a return on the Trojan investment and remanded the case to the OPUC for reconsideration.

In 2000, PGE entered into agreements to settle the litigation related to recovery of, and return on, its investment in Trojan. The settlement, which was approved by the OPUC, allowed PGE to remove from its balance sheet the remaining investment in Trojan as of September 30, 2000, along with several largely offsetting regulatory liabilities. After offsetting the investment in Trojan with these liabilities, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan was no longer included in prices charged to customers, either through a return of or a return on that investment. The Utility Reform Project (URP) did not participate in the settlement and filed a complaint with the OPUC challenging the settlement agreements. In 2002, the OPUC issued an order (2002 Order) denying all of the URP's challenges. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the 2002 Order to the OPUC for reconsideration.

The OPUC then issued an order in 2008 (2008 Order) that required PGE to provide refunds, including interest from September 30, 2000, to customers who received service from the Company during the period from October 1, 2000 to September 30, 2001. The Company recorded a charge of $33.1 million in 2008 related to the refund and accrued additional interest expense on the liability until refunds to customers were completed in the first quarter of 2010. The URP and the plaintiffs in the class actions described below separately appealed the 2008 Order to the Oregon Court of Appeals. On February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the 2008 Order. On May 31, 2013, the Court of Appeals denied the appellants' request for reconsideration of the decision. On October 18, 2013, the Oregon Supreme Court granted plaintiffs' petition seeking review of the February 6, 2013 Oregon Court of Appeals decision. Oral argument occurred in March 2014 and the parties now await a Court decision.

Class Actions. In two separate legal proceedings, lawsuits were filed in Marion County Circuit Court against PGE in 2003 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 2006, the Oregon Supreme Court issued a ruling ordering the abatement of the class action proceedings until the OPUC responded to the 2002 Order (described above). The Oregon Supreme Court concluded that the OPUC has primary jurisdiction to determine what, if any, remedy can 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 Oregon Supreme Court further stated that if the OPUC determined that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part. The Oregon Supreme Court added that, if the OPUC determined that it cannot provide a remedy, the court system may have a role to play. The Oregon Supreme Court also ruled that the plaintiffs retain the right to return to the Marion County Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. The Marion County Circuit Court subsequently abated the class actions in response to the ruling of the Oregon Supreme Court.

As noted above, on February 6, 2013, the Oregon Court of Appeals upheld the 2008 Order. Because the Oregon Supreme Court has granted the plaintiffs' petition seeking review of that decision, and the class actions described above remain pending, management believes that it is reasonably possible that the regulatory proceedings and class actions could result in a loss to the Company in excess of the amounts previously recorded and discussed above. Because these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine PGE's potential liability, if any, or to estimate a range of potential loss.

Pacific Northwest Refund Proceeding

In 2001, the FERC called for a hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001 (Pacific Northwest Refund proceeding). During that period, PGE both sold and purchased electricity in the Pacific Northwest. In 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Upon appeal of the decision to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit) the Court remanded the case to the FERC to, among other things, address market manipulation evidence in detail and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings.

In October 2011, the FERC issued an Order on Remand, establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC held that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome before a refund could be ordered. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets.

In December 2012, the FERC issued an order clarifying that the *Mobile-Sierra* presumption could be 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.

On April 5, 2013, the FERC granted rehearing of its Order on Remand on the issue of the appropriate refund period, holding that parties could pursue refunds for transactions between January 1, 2000 and December 24, 2000 under Section 309 of the Federal Power Act by showing violations of a filed tariff or rate schedule or of a statutory requirement. Refund claimants have filed petitions for appeal of the Order on Remand and the Order on Rehearing with the Ninth Circuit.

In its October 2011 Order on Remand, the FERC ordered settlement discussions to be convened before a FERC settlement judge. Pursuant to the settlement proceedings, the Company received notice of two claims and reached agreements to settle both claims for an immaterial amount. The FERC approved both settlements during 2012.

Additionally, the settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, et seq., approved by the FERC in May 2007, resolved all claims between PGE and the California parties named in the settlement, including the California Energy Resource Scheduling division of the California Department of Water Resources (CERS), as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 20, 2001, but did not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

The above-referenced settlements resulted in a release for the Company as a named respondent in the first phase of the remand proceedings, which are limited to initial and direct claims for refunds, but there remains a possibility that additional claims related to this matter could be asserted against the Company in a subsequent phase of the proceeding if refunds are ordered against some or all of the current respondents.

During the first phase of the remand hearing, now completed, two sets of refund proponents, the City of Seattle, Washington (Seattle) and various California parties on behalf of CERS, presented cases alleging that multiple respondents had engaged in unlawful activities and caused severe financial harm that justified the imposition of refunds. After conclusion of the hearing, the presiding Administrative Law Judge issued an Initial Decision on March 28, 2014 finding: i) that Seattle did not carry its *Mobile-Sierra* burden with respect to its refund claims against any of its respondent sellers; and ii) that the California representatives of CERS did not carry their *Mobile-Sierra* burden with respect to one of CERS' respondents, but did find evidence of unlawful activity in the implementation of multiple transactions and bad faith in the formation of as many as 119 contracts by the last remaining CERS respondent. The Administrative Law Judge scheduled a second phase of the hearing to commence after a final FERC decision on the Initial Decision. In the second phase, the last respondent will have an opportunity to produce additional evidence as to why its transactions should be considered legitimate and why refunds should not be ordered. If the FERC requires one or more respondents to make refunds, it is possible that such respondent(s) will attempt to recover similar refunds from their suppliers, including the Company.

Management believes that this matter could result in a loss to the Company in future proceedings. However, management cannot predict whether the FERC will order refunds from any of the current respondents, 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, will pursue additional refund claims against their suppliers, and, if so, what the basis or amounts of such potential refund claims against the Company would be. Due to these uncertainties, sufficient information is currently not available to determine PGE's liability, if any, or to estimate a range of reasonably possible loss.

EPA Investigation of Portland Harbor

A 1997 investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) 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 January 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 is currently undergoing a remedial investigation (RI) and feasibility study (FS) pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs known as the Lower Willamette Group (LWG), which does not include PGE.

In March 2012, the LWG submitted a draft FS to the EPA for review and approval. The draft FS, along with the RI, provide the framework for the EPA to determine a clean-up remedy for Portland Harbor that will be documented in a Record of Decision, which the EPA is not expected to issue before 2017.

The draft FS evaluates several alternative clean-up approaches. These approaches would take from two to 28 years with costs ranging from $169 million to $1.8 billion, depending on the selected remedial action levels and the choice of remedy. The draft FS does not address responsibility for the costs of clean-up, allocate such costs among PRPs, or define precise boundaries for the clean-up. Responsibility for funding and implementing the EPA's selected clean-up will be determined after the issuance of the Record of Decision.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties discussed above, sufficient information is currently not available to determine PGE's liability for the cost of any required investigation or remediation of the Portland Harbor site or to estimate a range of potential loss.

DEQ Investigation of Downtown Reach

The Oregon Department of Environmental Quality (DEQ) has executed a memorandum of understanding with the EPA to administer and enforce clean-up activities for portions of the Willamette River that are upriver from the Portland Harbor Superfund site (the Downtown Reach). In January 2010, the DEQ issued an order requiring PGE to perform an investigation of certain portions of the Downtown Reach. PGE completed this investigation in December 2011 and entered into a consent order with the DEQ in July 2012 to conduct a feasibility study of alternatives for remedial action for the portions of the Downtown Reach that were included within the scope of PGE's investigation. The draft feasibility study report, which describes possible remediation alternatives that range in estimated cost from $3 million to $8 million, was submitted to the DEQ in February 2014. Using the Company's best estimate of the probable cost for the remediation effort from the set of alternatives provided in the draft feasibility study report, PGE has a $3 million reserve for this matter as of June 30, 2014.

Based on the available evidence of previous rate recovery of incurred environmental remediation costs for PGE, as well as for other utilities operating within the same jurisdiction, the Company has concluded that the estimated cost of $3 million to remediate the Downtown Reach is probable of recovery. As a result, the Company also has a regulatory asset of $3 million for future recovery in prices as of June 30, 2014. The Company included recovery of the regulatory asset in its 2015 General Rate Case filed with the OPUC in February 2014.

Alleged Violation of Environmental Regulations at Colstrip

On July 30, 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the Clean Air Act (CAA) at Colstrip Steam Electric Station (CSES) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other CSES co-owners, including PPL Montana, LLC, the operator of CSES. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The Notice alleges certain violations of the CAA, including New Source Review, Title V, and opacity requirements, and states that the Sierra Club and MEIC will: i) request a United States District Court to impose injunctive relief and civil penalties; ii) require a beneficial environmental project in the areas affected by the alleged air pollution; and iii) seek reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees.

The Sierra Club and MEIC asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and that the owners have violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality (MDEQ). The Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

On March 6, 2013, the Sierra Club and MEIC sued the CSES co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs are seeking relief that includes an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter.

In September 2013, the plaintiffs filed an amended complaint that withdrew Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately forty additional projects. The CSES co-owners have filed a motion to dismiss all of the claims in the amended complaint. In April 2014, the parties entered into an agreement under which, following the court's decision on the motion to dismiss, plaintiffs will move to amend the complaint to limit the scope of the claims to thirteen projects. On May 22, 2014, the federal magistrate judge issued a recommendation to deny most of the motion to dismiss. The parties are awaiting a final decision on the motion to dismiss. This matter is scheduled for trial in June 2015.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome or determine whether it would have a material impact on the Company.

Challenge to AOC Related to Colstrip Wastewater Facilities

In August 2012, the operator of CSES entered into an AOC with the MDEQ, which established a comprehensive process to investigate and remediate groundwater seepage impacts related to the wastewater facilities at CSES. Within five years, under this AOC, the operator of CSES is required to provide financial assurance to MDEQ for the costs associated with closure of the waste water treatment facilities. This will establish an obligation for asset retirement, but the operator of CSES is unable at this time to estimate these costs, which will require both public and agency review.

In September 2012, Earthjustice filed an affidavit pursuant to Montana's Major Facility Siting Act (MFSA) that sought review of the AOC by Montana's Board of Environmental Review (BER), on behalf of environmental groups Sierra Club, the MEIC, and the National Wildlife Federation. In September 2012, the operator of CSES filed an election with the BER to have this proceeding conducted in Montana state district court as contemplated by the MFSA. In October 2012, Earthjustice, on behalf of Sierra Club, the MEIC and the National Wildlife Federation, filed with the Montana state district court a petition for a writ of mandamus and a complaint for declaratory relief alleging that the AOC fails to require the necessary actions under the MFSA and the Montana Water Quality Act with respect to groundwater seepage from the wastewater facilities at CSES. On May 31, 2013, the district court judge granted the defendants' motion to dismiss the petition for the writ of mandamus.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome or determine whether it would have a material impact on the Company.

Oregon Tax Court Ruling

On September 17, 2012, the Oregon Tax Court issued a ruling contrary to an Oregon Department of Revenue (DOR) interpretation and a current Oregon administrative rule, regarding the treatment of wholesale electricity sales. The underlying issue is whether electricity should be treated as tangible or intangible property for state income tax apportionment purposes. The DOR has appealed the ruling of the Oregon Tax Court to the Oregon Supreme Court. It is uncertain whether the ruling will be upheld. Oral argument occurred in May 2014 and the parties now await a Court decision.

If the ruling is upheld, PGE estimates that its income tax liability could increase by as much as $7 million due to an increase in the tax rate at which deferred tax liabilities would be recognized in future years. For open tax years per Oregon statute, 2008 through 2012, the Company entered into a closing agreement with the DOR during the third quarter 2013 under which the DOR agreed to the tax apportionment methodology utilized on the tax returns relating to those years.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome.

Other Matters

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

NOTE 8: GUARANTEES

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of June 30, 2014, 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 PGE to have a reasonable basis including, but not limited to, management's examination of historical operating trends and data contained in records and other data available from third parties, but there can be no assurance that PGE's expectations, beliefs or projections will be achieved or accomplished.

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

- governmental policies and regulatory audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- 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 disruption of fuel supply, which may cause the Company to incur repair costs, as well as increased power costs for replacement power;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, which could result in the Company's inability to recover project costs;
- volatility in wholesale power and natural gas prices, which could require PGE to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to existing power and natural gas purchase agreements;
- capital market conditions, including access to capital, interest rate volatility, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, and the repayments of maturing debt;
- future laws, regulations, and proceedings that could increase the Company's costs or affect the operations of the Company's thermal generating plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- changes in wholesale prices for fuels, including natural gas, coal and oil, and the impact of such changes on the Company's power costs;
- changes in the availability and price of wholesale power;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures;
- declines in the fair value of securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- changes in, and compliance with, environmental and endangered species laws and policies;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;

- new federal, state, and local laws that could have adverse effects on operating results;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities or information technology systems, or result in the release of confidential customer and proprietary information;
- employee workforce factors, including a significant number of employees approaching retirement, potential strikes, work stoppages, and transitions in senior management;
- political, economic, and financial market conditions;
- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;
- financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Overview

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide an understanding of the business environment, results of operations, and financial condition of PGE. MD&A should be read in conjunction with the Company's 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, 2013, and other periodic and current reports filed with the SEC.

Capital Requirements and Financing—Pursuant to PGE's latest acknowledged Integrated Resource Plan (IRP), PGE is in the process of constructing the following three new generation resources:

- *Port Westward Unit 2* (PW2)—Construction commenced in May 2013 on PW2, which is a 220 MW natural gas-fired plant located adjacent to the Port Westward and Beaver natural gas-fired generating plants near Clatskanie, Oregon. This project is currently on budget at an estimated total cost of $300 million, excluding the allowance for funds used during construction (AFDC), and is expected to be online in the first quarter of 2015. As of June 30, 2014, $231 million, including $12 million of AFDC, is included in CWIP for PW2. The Company has requested in its 2015 General Rate Case (2015 GRC) that cost recovery for the project begin at the point at which the plant is placed into service;
- *Tucannon River wind farm* (Tucannon River)—Construction commenced in September 2013 on Tucannon River, which is a wind farm located in southeastern Washington with a nameplate capacity of 267 MW, consisting of 116 turbines each with a generating capacity of 2.3 MW. This project is currently on budget at an estimated total cost of $500 million, excluding AFDC, and is expected to be online between December 2014 and March 31, 2015. As of June 30, 2014, $363 million, including $9 million of AFDC, is included in CWIP for Tucannon River. The Company had requested recovery of costs related to the project in its 2015 GRC to begin when the plant is placed into service, which at the time was expected to be in the first half of 2015. However, in March 2014, PGE submitted a renewable adjustment clause mechanism (RAC) filing to the OPUC to allow for deferral and recovery of costs to begin earlier if the project should come online earlier than contemplated in the 2015 GRC; and
- *Carty Generating Station* (Carty)—Construction commenced in January 2014 on Carty, which is a 440 MW natural gas-fired power plant located in Eastern Oregon, adjacent to Boardman. This project is currently on budget at an estimated total cost of $450 million, excluding AFDC, and is expected to be online in mid-2016. As of June 30, 2014, $191 million, including $9 million of AFDC, is included in CWIP for Carty. The Company expects to file for recovery of costs related to this project in a future general rate case.

In total, the Company's capital expenditures in 2014 are expected to approximate $1 billion, which includes an estimated $640 million related to the three new generation resources under construction discussed above. For additional information on the timing of expenditures for these three new generation resources, see *"Capital Requirements"* in the Liquidity and Capital Resources section of this Item 2.

PGE expects to fund 2014 estimated capital requirements with a combination of cash from operations, which is expected to range from $540 million to $560 million, and proceeds from long-term bank loans and issuances of FMBs of $585 million. For additional information, see *"Liquidity"* and *"Debt and Equity Financings"* in the Liquidity and Capital Resources section of this Item 2.

General Rate Case—On January 1, 2014, new customer prices went into effect pursuant to the OPUC order issued on PGE's 2014 General Rate Case (2014 GRC). The OPUC authorized a $61 million increase in annual revenues, representing an approximate 4% overall increase in customer prices. The increase includes improvements to existing power plants and wind forecasting, new Clackamas River fish-sorting facilities, a disaster-preparedness center, technology investments, employee benefit costs and compliance with new federal regulations. In addition, the order approved a capital structure of 50% debt and 50% equity, a return on equity of 9.75%, a cost of capital of 7.65%, and an average rate base of approximately $3.1 billion.

On February 13, 2014, PGE filed a 2015 GRC with the OPUC that is based on a 2015 test year. PGE originally requested an $81 million net increase in annual revenues, representing an approximate 4.6% overall increase in customer prices, with a proposed capital structure of 50% debt and 50% equity, a return on equity of 10%, and an average rate base of approximately $3.9 billion. On July 16, 2014, PGE filed testimony supporting a revised revenue requirement in the 2015 GRC proceeding, reflecting the impacts of stipulations reached to date with Staff and interveners, updates to 2015 power cost and load forecasts, and other updates. The stipulations are subject to OPUC approval. The net increase in annual revenues as originally proposed in the Company's initial filing and as revised consist of the following (in millions):

	As Filed February 13, 2014	Depreciation Stipulation (1)	Other Updates and Stipulations (2)	As Revised July 16, 2014
New generating plants:				
Port Westward Unit 2	$ 51	$ (5)	$ 3	$ 49
Tucannon River wind farm	47	(3)	(4)	40
Base business cost change	12	(11)	(30)	(29)
Less: customer credits (3)	(29)	—	—	(29)
Annual revenue net increase	$ 81	$ (19)	$ (31)	$ 31

(1) On December 5, 2013, PGE filed with the OPUC a depreciation study (Docket UM 1679) with estimated parameters for service life and salvage assumptions for all of the Company's assets, for which assumptions in the 2015 GRC filing were based. As a result of a stipulation filed on June 30, 2014 in the depreciation study proceeding, PGE's requested revenue increase in the 2015 GRC was reduced by a total of approximately $19 million.

(2) Includes various cost updates ($9 million), changes in the timing of certain projects ($6 million), corrections to the Company's original filing ($4 million), other agreements ($7 million), and postponement of the recognition of a prepaid pension asset to another proceeding (Docket UM 1633) ($5 million).

(3) Includes approximately $17 million for the return of $50 million over three years, 2015 through 2017, for the settlement of a legal matter concerning costs associated with the operation of the Independent Spent Fuel Storage Installation (ISFSI) at Trojan. Also includes credits related to the return of ISFSI tax credits to customers and additional Bonneville Power Administration (BPA) Regional Power Act refund to residential customers.

As revised, the expected increase in annual revenues is $31 million, or an overall increase of approximately 1.8% in customer prices, with an average rate base of approximately $3.8 billion. The cost of long-term debt and the capital structure of 50% debt and 50% equity have been resolved through stipulations. The remaining unresolved issues in the 2015 GRC include, among other things, the return on equity, modifications to the PCAM, the recovery of costs related to PW2 and Tucannon River, along with final updates to the load and power cost forecasts, any or all of which may further change the amounts reflected in the table above.

Regulatory review of the 2015 GRC will continue throughout 2014, with a final order expected to be issued by the OPUC by mid-December 2014. New customer prices are expected to become effective in 2015, with the first price increase effective January 1 and two additional price increases effective as the two new generating plants become operational. PW2 is expected to be placed in service in the first quarter of 2015 and Tucannon River is expected to be placed in service between December 2014 and March 31, 2015.

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

The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues and income from operations to fluctuate from period to period. PGE is a winter-peaking utility that typically experiences its highest retail energy sales during the winter heating season, although a slightly lower peak occurs in the summer that generally results from air conditioning demand. Price changes and customer usage patterns, which can be affected by the economy, also have an effect on revenues while the availability and price of purchased power and fuel can affect income from operations.

Customers and Demand—Retail energy deliveries for the first half of 2014 decreased 1.1% from the first half of 2013, which was primarily driven by a decline in residential energy deliveries, resulting from warmer weather conditions, and a decline in industrial energy deliveries largely due to decreased demand from a paper production customer. Energy efficiency and conservation efforts by retail customers continue to influence total energy deliveries, although the financial impacts to the Company of such efforts are partially mitigated by the decoupling mechanism. The decline was partially offset by the effects of a 1% increase in the average number of total retail customers served.

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

	Six Months Ended June 30,				
	2014		2013		% Increase /(Decrease)in Energy Deliveries
	Average Number of Customers	Retail Energy Deliveries*	Average Number of Customers	Retail Energy Deliveries*	
Residential	734,218	3,726	726,960	3,809	(2.2)%
Commercial	104,674	3,595	103,798	3,583	0.3
Industrial	260	2,058	268	2,088	(1.4)
Total	839,152	9,379	831,026	9,480	(1.1)

* 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 wholesale market transactions. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, PGE makes economic dispatch decisions continuously in an effort to obtain reasonably-priced power for its retail customers. In addition, PGE's thermal generating plants require varying levels of annual maintenance, during which the respective plant is unavailable to provide power. As a result, the amount of power generated and purchased in the wholesale market to meet the Company's retail load requirement can vary from period to period. During the six months ended June 30, 2014 and 2013, availability of the plants PGE operates approximated 89% and 90%, respectively, with the availability of Colstrip Units 3 and 4, in which the Company has a 20% ownership interest but does not operate, approximating 87% and 84%, respectively. Colstrip Unit 4 was off-line most of the month of January 2014 due to repairs to the generator. As a result, PGE incurred approximately $2 million of incremental replacement power costs in the first quarter of 2014 related to this plant outage.

During the first half of 2014, the Company's generating plants provided approximately 46% of its retail load requirement, compared with 53% in the first half of 2013. The decrease in the proportion of power generated to meet the Company's retail load requirement was largely the result of the difference in the economic dispatch decisions made throughout the respective periods, as well as the outage of Colstrip Unit 4 in January 2014.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects increased 2% in the first half of 2014 compared with the first half of 2013. These resources provided approximately 20% of the Company's retail load requirement for the six months ended June 30, 2014 and 2013. Through June, energy received from these sources exceeded projected levels included in the Company's Annual

Power Cost Update Tariff (AUT) for 2014 by 2%, compared with the same period of 2013, which exceeded projections included in the AUT for 2013 by 1%. Any excess in hydro generation from that projected in the AUT generally displaces power from higher cost sources, while any shortfall is generally replaced with power from higher cost sources. Based on recent forecasts of regional hydro conditions for 2014, energy from hydro resources is expected to be slightly above projected levels included in the AUT for 2014.

Energy expected to be received from PGE-owned wind generating resources (Biglow Canyon) is projected annually in the AUT. Any excess in wind generation from that projected in the AUT generally displaces power from higher cost sources, while any shortfall is generally replaced with power from higher cost sources. Energy received from Biglow Canyon fell short of that projected in PGE’s AUT by 5% for the six months ended June 30, 2014 and 9% for the six months ended June 30, 2013, and provided approximately 7% of the Company’s retail load requirement for the first half of 2014 and 2013.

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 operations) and is net of wholesale revenues, which are classified as Revenues, net in the condensed consolidated statements of operations. To the extent actual NVPC, subject to certain adjustments, is above or below the deadband, the PCAM provides for 90% of the variance to be collected from or refunded to customers, respectively, subject to a regulated earnings test. Pursuant to the regulated earnings test, a refund will occur only to the extent that it results in PGE’s actual regulated return on equity (ROE) for that year being no less than 1% above the Company’s latest authorized ROE, while a collection will occur only to the extent that it results in PGE’s actual regulated ROE for that year being no greater than 1% below the Company’s authorized ROE. Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues in the Company’s condensed consolidated statements of operations, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense. The deadband range is from $15 million below to $30 million above baseline NVPC.

For the first half of 2014, actual NVPC was approximately $14 million below baseline NVPC. Based on forecast data, NVPC for the year ending December 31, 2014 is currently estimated to be below baseline NVPC, but within the deadband range; accordingly, no estimated collection from, or refund to, customers is expected under the PCAM for 2014.

For the first half of 2013, actual NVPC was approximately $14 million below baseline NVPC. For the full year 2013, actual NVPC was $11 million above baseline NVPC, which is within the established deadband range. Accordingly, no estimated collection from customers was recorded under the PCAM for 2013.

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:

- Challenges to recovery of the Company’s investment in its closed Trojan plant;
- Claims for refunds related to wholesale energy sales during 2000 - 2001 in the Pacific Northwest Refund Proceeding; and
- An investigation of environmental matters regarding Portland Harbor.

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

On June 2, 2014, the EPA released a proposed rule, which it calls the “Clean Power Plan.” The proposed rule is intended to result in a reduction of carbon emissions from existing power plants across all states to approximately 30 percent below 2005 levels by 2030. Under the proposed 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 proposed rule would establish state goals in terms of pounds of carbon dioxide emitted per MWh. The target amount was determined by the EPA’s view of each state’s options, including: i) making power plant efficiency upgrades; ii) shifting generation from coal-fired plants to natural gas-fired plants; iii) expanding use of zero- and low-carbon emitting generation (such as renewable energy and nuclear energy); and iv) implementing customer energy efficiency programs. The final goal would need to be met in 2030 and an interim goal for each state would need to be met on average over the 10-year period from 2020 to 2029. Under the proposed rule, states would have flexibility in designing programs to meet their emission reduction targets, including the four 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.

The EPA is scheduled to finalize the proposed rule by June 1, 2015. If finalized by such date, states would have until June 30, 2016 to submit plans to implement the rule (subject to extension). The Company cannot predict whether the proposed rule will be adopted or, if adopted, i) how the states in which the Company’s generation facilities are located will implement the rule or ii) the impact of the rule on the Company’s operations. However, the rule, if adopted as proposed, could result in increased operating costs.

The following discussion highlights certain regulatory items that have impacted the Company’s revenues, results of operations, or cash flows for the six months ended June 30, 2014 compared to the six months ended June 30, 2013 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 2014 GRC, PGE included a projected $17 million reduction in power costs in its request for an overall increase in revenues. The power cost portion of the request was moved to a separate docket at the OPUC and was approved and included in the overall $61 million annual revenue increase authorized by the OPUC in the Company’s 2014 GRC with new prices beginning January 1, 2014.

  Under the PCAM for 2013, NVPC were within the limits of the deadband, thus no potential refund or collection was recorded. The OPUC is currently reviewing the results of the Company’s PCAM for 2013, with an order expected by the end of this year.

- 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.

  In March 2014, PGE submitted to the OPUC a renewable adjustment clause filing requesting deferral and recovery of the net revenue requirement of Tucannon River in the event that the facility were to come online prior to the inclusion of the project in base rates as proposed in the 2015 GRC. The Company estimates that the project will be in service between December 2014 and March 31, 2015.

  PGE did not submit a RAC filing to the OPUC in 2013 as it did not place renewable resources into service during 2013.

- Decoupling—The decoupling mechanism, which the OPUC has authorized through 2016, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. 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.

  Pursuant to the Company’s 2014 GRC, the OPUC approved a change in the refund or collection period such that it will begin January 1, rather than June 1. Accordingly, collection of the estimated $5 million recorded during 2013, is expected, subject to OPUC approval, to occur largely over a one year period beginning January 1, 2015.

  For the six months ended June 30, 2014, the Company has recorded an estimated collection of $3 million. Any resulting collection from customers for the 2014 year would begin January 1, 2016.

- Capital deferral—In the 2011 General Rate Case, the OPUC authorized the Company to defer the costs associated with four capital projects that were not completed at the time the 2011 General Rate Case was approved. A regulatory asset of $16 million was recorded in 2012, for potential recovery in customer prices, subject to an earnings test, with an offsetting credit to Depreciation and amortization expense. The OPUC authorized recovery of the deferred costs over a one year period, with a resulting tariff effective January 1, 2014. During 2013, the Company deferred an additional $18 million of costs associated with these projects and in July 2014 filed for recovery of the additional costs, subject to an earnings test, with new customer prices expected to be effective in January 2015.

- Boardman Operating Life Adjustment—As part of the 2014 GRC, the incremental depreciation expense that resulted from the shortened Boardman life was included in base customer prices, while recovery of the decommissioning costs continue under this separate tariff. During the second quarter 2014, the OPUC approved the request for recovery of additional decommissioning costs that resulted from the acquisition of the additional 15% interest in Boardman on December 31, 2013, which is expected to result in approximately $3 million additional revenue in 2014. The tariff also provides for annual updates to decommissioning revenue requirements with revised prices to take effect each January 1.

Integrated Resource Plan—PGE’s IRP outlines how the Company will meet future customer demand and describes PGE’s future energy supply strategy, assessing both new and existing technologies, market conditions, and regulatory requirements.

On March 27, 2014, PGE filed a new IRP (2013 IRP) with the OPUC, which outlines the Company’s expectations for resource needs and resource portfolio performance over the next 20 years, and includes an “Action Plan,” which covers PGE’s proposed actions over the next two to four years (through 2017). Over this time period, the Company projects energy requirements and energy available through its generation resources and long-term power purchase agreements to be in approximate balance.

The Action Plan of the 2013 IRP includes the following, among other components, between 2014 and 2017:

- Seek renewal, or partial renewal, of expiring power purchase agreements for energy generated from hydroelectric projects, if available and cost-effective for our customers;
- Acquire a total of 124 MWa of energy efficiency through continuation of Energy Trust of Oregon programs;
- To help manage peak load conditions and other supply contingencies, acquire 48 MW of demand response and PGE dispatchable standby generation from our customers;
- In preparation for the next IRP, perform various research and studies related to load forecast and energy efficiency projections, distributed photovoltaic solar application within PGE's service territory, the viability of large-scale biomass operations, fuel supply, wind integration needs, and operational flexibility requirements; and
- Retain and acquire transmission service through BPA's Open Access Transmission Tariff to interconnect new and existing resources in eastern Oregon to PGE's service territory.

The 2013 IRP also incorporates the three new resources that are currently under construction, which are expected to be in service between December 2014 and mid-2016. For additional information on these capital projects see *"Capital Requirements and Financing"* in the Overview section in this Item 2.

OPUC review of the 2013 IRP will continue throughout 2014, with an acknowledgement from the OPUC not expected before September 2014.

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, 2013, filed with the SEC on February 14, 2014.

Results of Operations

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
Revenues, net	$ 423	100%	$ 403	100 %	$ 916	100%	$ 876	100 %
Purchased power and fuel	142	34	156	39	326	36	348	40
Gross margin	281	66	247	61	590	64	528	60
Other operating expenses:								
Production and distribution	67	16	64	16	121	13	115	13
Cascade Crossing transmission project	—	—	52	13	—	—	52	6
Administrative and other	56	13	55	14	110	12	109	12
Depreciation and amortization	73	17	62	15	148	16	124	14
Taxes other than income taxes	27	6	25	6	55	6	52	6
Total other operating expenses	223	52	258	64	434	47	452	51
Income (loss) from operations	58	14	(11)	(3)	156	17	76	9
Interest expense*	23	5	25	6	48	5	50	6
Other income:								
Allowance for equity funds used during construction	9	2	2	1	15	1	4	1
Miscellaneous income, net	1	—	1	—	—	—	2	—
Other income, net	10	2	3	1	15	1	6	1
Income (loss) before income tax expense (benefit)	45	11	(33)	(8)	123	13	32	4
Income tax expense (benefit)	10	3	(11)	(3)	30	3	6	1
Net income (loss)	35	8	(22)	(5)	93	10	26	3
Less: net loss attributable to noncontrolling interests	—	—	—	—	—	—	(1)	—
Net income attributable to Portland General Electric Company	$ 35	8%	$ (22)	(5)%	$ 93	10%	$ 27	3 %
* Includes an allowance for borrowed funds used during construction of	$ 5		$ 1		$ 9		$ 2	

Net income attributable to Portland General Electric Company was $35 million, or $0.43 per diluted share, for the second quarter of 2014, compared with a net loss of $22 million, or $0.29 per diluted share, for the second quarter of 2013. The change in Net income (loss) was driven by an increase in the average retail price resulting from the January 1, 2014 price increase authorized by the OPUC in the Company's 2014 GRC, lower net variable power costs, and an increase in AFDC resulting from a higher average CWIP balance driven by the construction of PW2, Tucannon River, and Carty. Additionally, during the second quarter of 2013, the Company charged to expense $52 million of capitalized costs related to Cascade Crossing Transmission Project and recorded a refund of $9 million to an industrial customer for cumulative over-billings over a period of several years.

Net income attributable to PGE for the six months ended June 30, 2014 was $93 million, or $1.16 per diluted share, compared with $27 million, or $0.36 per diluted share, for the six months ended June 30, 2013. The increase in Net income was driven by an increase in the average retail price resulting from the January 1, 2014 price increase authorized by the OPUC in the Company's 2014 GRC, lower net variable power costs, and an increase in AFDC resulting from a higher average CWIP balance. Additionally, during the second quarter of 2013, the Company charged to expense $52 million of capitalized costs related to Cascade Crossing Transmission Project and recorded a refund of $9 million to an industrial customer for cumulative over-billings over a period of several years.

Three Months Ended June 30, 2014 Compared with the Three Months Ended June 30, 2013

Revenues, energy deliveries (presented in MWh), and the average number of retail customers were as follows for the periods presented:

	Three Months Ended June 30,			
	2014		2013	
Revenues (1) (dollars in millions):				
Retail:				
Residential	$ 188	44 %	$ 179	45 %
Commercial	159	38	150	37
Industrial	53	13	54	13
Subtotal	400	95	383	95
Other retail revenues, net	(4)	(1)	(10)	(2)
Total retail revenues	396	94	373	93
Wholesale revenues	17	4	21	5
Other operating revenues	10	2	9	2
Total revenues	$ 423	100 %	$ 403	100 %
Energy deliveries (2) (MWh in thousands):				
Retail:				
Residential	1,552	32 %	1,580	30 %
Commercial	1,814	37	1,796	35
Industrial	1,057	21	1,064	20
Total retail energy deliveries	4,423	90	4,440	85
Wholesale energy deliveries	512	10	771	15
Total energy deliveries	4,935	100 %	5,211	100 %
Average number of retail customers:				
Residential	734,716	87 %	727,470	87 %
Commercial	105,662	13	104,831	13
Industrial	259	—	263	—
Total	840,637	100 %	832,564	100 %

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.
(2) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

Total revenues increased $20 million, or 5%, for the second quarter of 2014 compared with the second quarter of 2013, largely due to the $23 million increase in Retail revenues resulting from the following:

- A $14 million increase in the average retail price resulting from the January 1, 2014 price increase authorized by the OPUC in the Company's 2014 GRC;
- A $9 million increase as a result of the industrial customer refund recorded in the second quarter of 2013 (reflected in Other retail revenues, net in the preceding table) related to cumulative over-billings during a period of several years as a result of a meter configuration error. Management believes the customer billing error is not material to any past reporting period. Accordingly, the Company corrected this matter in the second quarter of 2013 through an out of period adjustment as a reduction to Revenues, net; and
- A $5 million increase related to an increase in the average retail price for the amortization of deferred costs related to four capital projects beginning January 1, 2014 (offset in Depreciation and amortization expense); partially offset by
- A $3 million decrease related to various items, including the decoupling mechanism and other supplemental tariff changes; and
- A $2 million decrease related to 0.4% lower volumes of energy delivered driven by declines of 1.8% in residential energy deliveries and 0.7% in industrial energy deliveries, which was partially offset by a 1.0% increase in commercial energy deliveries. After adjusting for the effects of weather, total retail energy deliveries were down 0.1% for the second quarter of 2014 compared with the second quarter of 2013.

Total heating degree-days for the second quarter of 2014 were 11% lower than the second quarter of 2013 and 26% below average. The following table indicates the number of heating and cooling degree-days for the second quarters of 2014 and 2013, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		Cooling Degree-days	
	2014	2013	2014	2013
April	332	372	3	—
May	136	172	25	15
June	62	49	29	67
Second quarter	530	593	57	82
15-year average for the year-to-date	713	721	70	68

Wholesale revenues result from sales of electricity to utilities and power marketers in conjunction with the Company's efforts to secure reasonably-priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. Such sales can vary significantly from period to period as a result of economic conditions, power and fuel prices, hydro and wind conditions, and customer demand. The $4 million, or 19%, decrease in Wholesale revenues for the second quarter of 2014 compared with the second quarter of 2013, consisted of $7 million related to a 34% decrease in wholesale sales volume partially offset by $3 million related to a 22% increase in average wholesale price.

Purchased power and fuel expense decreased $14 million, or 9%, for the second quarter of 2014 compared with the second quarter of 2013, and consisted of $10 million related to a 7% decrease in total system load and $4 million related to a 3% decrease in the average variable power cost per MWh. The decrease in the average variable power cost to $30.05 per MWh in the second quarter of 2014 from $30.84 per MWh in the second quarter of 2013 was driven by the economic displacement of a greater amount of thermal generation with purchased power during the second quarter of 2014 relative to the second quarter of 2013, combined with an increase in energy received from wind generating resources.

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

	Three Months Ended June 30,			
	2014		2013	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	367	8%	794	16%
Natural gas	43	1	228	4
Total thermal	410	9	1,022	20
Hydro	448	9	436	9
Wind	404	9	384	7
Total generation	1,262	27	1,842	36
Purchased power:				
Term	2,562	54	2,571	51
Hydro	489	11	508	10
Wind	102	2	111	2
Spot	294	6	19	1
Total purchased power	3,447	73	3,209	64
Total system load	4,709	100%	5,051	100%
Less: wholesale sales	(512)		(771)	
Retail load requirement	4,197		4,280	

Energy received from hydro resources during the second quarter of 2014, from both PGE-owned generating plants and purchased from mid-Columbia projects, decreased 1% compared with the second quarter of 2013. These resources provided approximately 22% of the Company's retail load requirement during the second quarters of 2014 and 2013. During the second quarter, total energy received from hydro resources exceeded projected levels included in the AUT for 2014 by 4%, compared with the second quarter of 2013, which exceeded projected levels included in the AUT for 2013 by 5%.

The following table presents the forecast of the April-to-September 2014 runoff (issued July 25, 2014), along with actual for 2013, 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 1971 through 2000):

	Runoff as a Percent of Normal *	
Location	2014 Forecast	2013 Actual
Columbia River at The Dalles, Oregon	108%	100%
Mid-Columbia River at Grand Coulee, Washington	112	108
Clackamas River at Estacada, Oregon	95	102
Deschutes River at Moody, Oregon	97	98

* 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.

Energy from PGE-owned wind generating resources (Biglow Canyon) increased 5% in the second quarter of 2014 compared to the second quarter of 2013, and represented 10% of the Company's retail load requirement for the second quarters of 2014 and 2013. Energy received from Biglow Canyon fell short of that projected in PGE's AUT by 1% in the second quarter of 2014, compared with 8% in the second quarter of 2013.

Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, decreased approximately $10 million for the second quarter of 2014 compared with the second quarter of 2013. The decrease was due to a 7% decline in total system load, a 3% decline in the average variable power cost per MWh and a 22% increase in the average wholesale sales price, partially offset by a 34% decrease in wholesale sales volume. For the second quarters of 2014 and 2013, actual NVPC was $11 million and $13 million, respectively, below baseline NVPC.

Production and distribution expense increased $3 million, or 5%, in the second quarter of 2014 compared with the second quarter of 2013. The increase is largely due to $2 million of additional operating costs as a result of the Company's ownership interest in Boardman increasing to 80% from 65% on December 31, 2013, and $1 million higher maintenance outage expense in 2014.

Cascade Crossing transmission project of $52 million in the second quarter of 2013 reflects the charge to expense of project costs previously recorded as CWIP. For further information, see "Electric Utility Plant, Net" in Note 2, Balance Sheet Components, in the Notes to Condensed Consolidated Financial Statements.

Depreciation and amortization expense increased $11 million, or 18%, in the second quarter of 2014 compared with the second quarter of 2013, with $8 million related to timing of the deferral and amortization of costs of four capital projects as authorized in the Company's 2011 General Rate Case. In the second quarter of 2013, PGE deferred for future recovery $4 million of costs related to these four projects and in the second quarter of 2014, the Company recorded $4 million of amortization expense related to the recovery of these costs (offset in Retail revenues). In addition, capital additions increased Depreciation and amortization expense by $4 million.

Taxes other than income taxes expense increased $2 million, or 8%, in the second quarter of 2014 compared with the second quarter of 2013, primarily due to higher property taxes resulting from increased property values.

Interest expense decreased $2 million, or 8%, in the second quarter of 2014 compared with the second quarter of 2013. A $4 million decrease related to higher allowance for borrowed funds used during construction resulting from a higher average CWIP balance driven by the construction of PW2, Carty and Tucannon River was partially offset by an increase related to an increase in the average balance of debt outstanding in the second quarter of 2014.

Other income, net increased $7 million in the second quarter of 2014 compared with the second quarter of 2013, which was due to an increase in the allowance for equity funds used during construction from the higher average CWIP balance.

Income tax expense was $10 million in the second quarter of 2014 compared with a benefit of $11 million in the second quarter of 2013. The change is primarily due to the increase in the annual estimated pre-tax income for 2014 compared to 2013, which was driven by the charge to expense related to Cascade Crossing and an industrial customer refund recorded in 2013, offset by a favorable income tax benefit in 2014 related to an increase in the allowance for equity funds used during construction.

Six Months Ended June 30, 2014 Compared with the Six Months Ended June 30, 2013

Revenues, energy deliveries (presented in MWh), and the average number of retail customers were as follows for the periods presented:

	Six Months Ended June 30,			
	2014		2013	
Revenues [1] (dollars in millions):				
Retail:				
Residential	$ 445	48 %	$ 425	49 %
Commercial	317	35	299	34
Industrial	105	11	105	12
Subtotal	867	94	829	95
Other retail revenues, net	(2)	—	(6)	(1)
Total retail revenues	865	94	823	94
Wholesale revenues	34	4	37	4
Other operating revenues	17	2	16	2
Total revenues	$ 916	100 %	$ 876	100 %
Energy deliveries [2] (MWh in thousands):				
Retail:				
Residential	3,726	36 %	3,809	35 %
Commercial	3,595	35	3,583	33
Industrial	2,058	20	2,088	20
Total retail energy deliveries	9,379	91	9,480	88
Wholesale energy deliveries	893	9	1,311	12
Total energy deliveries	10,272	100 %	10,791	100 %
Average number of retail customers:				
Residential	734,218	88 %	726,960	87 %
Commercial	104,674	12	103,798	13
Industrial	260	—	268	—
Total	839,152	100 %	831,026	100 %

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.
(2) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

Total revenues increased $40 million, or 5%, for the first half of 2014 compared with the first half of 2013, largely due to the $42 million increase in Retail revenues resulting from the following:

- A $35 million increase in the average retail price resulting from the January 1, 2014 price increase authorized by the OPUC in the Company's 2014 GRC;
- A $9 million increase as a result of the industrial customer refund recorded in the second quarter of 2013 (reflected in Other retail revenues, net in the preceding table) related to cumulative over-billings during a period of several years as a result of a meter configuration error; and
- A $9 million increase related to an increase in the average retail price for the amortization of deferred costs related to four capital projects beginning January 1, 2014 (offset in Depreciation and amortization expense); partially offset by
- A $9 million decrease related to 1.1% lower volumes of energy delivered largely driven by declines of 2.2% in residential energy deliveries and 1.4% in industrial energy deliveries. Commercial energy deliveries in

the first half of 2014 were comparable to the first half of 2013. After adjusting for the effects of weather, total retail energy deliveries were down 1.4% for the first half of 2014 compared with the first half of 2013; and

- A $2 million decrease related to various items, including the decoupling mechanism and other supplemental tariff changes.

Total heating degree-days for the first half of 2014 were 3% lower than the first half of 2013 and 6% below average. The following table indicates the number of heating and cooling degree-days for the six months ended June 30, 2014 and 2013, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		**Cooling Degree-days**	
	2014	**2013**	**2014**	**2013**
First quarter	1,891	1,902	—	—
Second quarter	530	593	57	82
Year-to-date	2,421	2,495	57	82
15-year average for the year-to-date	2,577	2,571	70	68

Wholesale revenues for the first half of 2014 decreased $3 million, or 8%, from the first half of 2013, and consisted of $12 million related to a 32% decrease in wholesale sales volume partially offset by $9 million related to a 35% increase in average wholesale price.

Purchased power and fuel expense decreased $22 million, or 6%, for the first half of 2014 compared with the first half of 2013, and consisted of $17 million related to a 5% decrease in total system load and $5 million related to a 1% decrease in the average variable power cost per MWh. The decrease in the average variable power cost to $32.42 per MWh in the first half of 2014 from $32.90 per MWh in the first half of 2013 was driven by the economic displacement of a greater amount of thermal generation with purchased power during 2014 relative to 2013, combined with an increase in energy received from hydro resources. In addition, the Company incurred approximately $2 million of incremental replacement power costs related to the outage of Colstrip Unit 4 during January 2014.

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

	Six Months Ended June 30,			
	2014		2013	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	1,600	16%	2,155	20%
Natural gas	991	10	1,204	11
Total thermal	2,591	26	3,359	31
Hydro	981	10	917	9
Wind	621	6	629	6
Total generation	4,193	42	4,905	46
Purchased power:				
Term	3,782	38	3,881	37
Hydro	867	8	901	8
Wind	165	2	177	2
Spot	1,041	10	703	7
Total purchased power	5,855	58	5,662	54
Total system load	10,048	100%	10,567	100%
Less: wholesale sales	(893)		(1,311)	
Retail load requirement	9,155		9,256	

Energy received from hydro resources during the first half of 2014, from both PGE-owned generating plants and purchased from mid-Columbia projects, increased 2% compared with the first half of 2013. These resources provided approximately 20% of the Company’s retail load requirement during the first half of 2014 and 2013. Through June, total energy received from hydro resources exceeded projected levels included in the AUT for 2014 by 2%, compared with the same period of 2013, which exceeded such projected levels included in the AUT for 2013 by 1%.

Energy from PGE-owned wind generating resources (Biglow Canyon) decreased 1% in the first half of 2014 compared to the first half of 2013, and represented 7% of the Company’s retail load requirement for the six months ended June 30, 2014 and 2013. Energy received from Biglow Canyon fell short of that projected in PGE’s AUT by 5% for the six months ended June 30, 2014 and 9% for the six months ended June 30, 2013.

Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, decreased approximately $19 million for the first half of 2014 compared with the first half of 2013. The decrease was due to a 5% decline in total system load, a 35% increase in the average wholesale sales price and a 1% decline in the average variable power cost per MWh, partially offset by a 32% decrease in wholesale sales volume. For the six months ended June 30, 2014 and 2013, actual NVPC was $14 million below baseline NVPC.

Production and distribution expense increased $6 million, or 5%, in the first half of 2014 compared with the first half of 2013. The increase is largely due to $4 million higher operating costs as a result of the Company’s ownership interest in Boardman increasing to 80% from 65% on December 31, 2013. Storm, service restoration costs, and labor were collectively $4 million higher in 2014, and planned maintenance outage expenses at the PGE’s generation facilities in 2014 were $2 million greater than in 2013. Partially offsetting these increases was a $4 million decrease due to a reserve recorded in the first quarter of 2013 related to the Company’s benchmark bid, which was not selected as a winning bid in the request for proposal for renewable resources pursuant to PGE’s 2009 IRP.

Cascade Crossing transmission project of $52 million in the first half of 2013 reflects the charge to expense of costs previously recorded as CWIP.

Depreciation and amortization expense increased $24 million, or 19%, in the first half of 2014 compared with the first half of 2013, with $16 million related to timing of the deferral and amortization of costs of four capital projects as authorized in the Company’s 2011 General Rate Case. In the first half of 2013, PGE deferred for future recovery $8 million of costs related to these four projects and in the first half of 2014, the Company recorded $8 million of amortization expense related to the recovery of these costs (offset in Retail revenues). In addition, capital additions increased Depreciation and amortization expense by $8 million.

Taxes other than income taxes expense increased $3 million, or 6%, in the first half of 2014 compared with the first half of 2013, primarily due to higher property taxes resulting from increased property values.

Interest expense decreased $2 million, or 4%, in the first half of 2014 compared with the first half of 2013. A $7 million increase related to an increase in the allowance for borrowed funds used during construction resulting from a higher average CWIP balance driven by the construction of PW2, Carty and Tucannon River was partially offset by an increase related to an increase in the average balance of debt outstanding in the first half of 2014.

Other income, net increased $9 million in the first half of 2014 compared with the first half of 2013, primarily due to an $11 million increase in the allowance for equity funds used during construction from the higher average CWIP balance, partially offset by a decrease in earnings from the Non-qualified benefit plan trust assets.

Income tax expense increased $24 million in the first half of 2014 compared with the first half of 2013, with effective tax rates of 24.4% and 18.8%, respectively. The increases in income tax expense and the effective tax rate are primarily due to an increase in estimated annual pre-tax income for 2014 compared to 2013, partially offset by a favorable income tax benefit in 2014 related to an increase in the allowance for equity funds used during construction.

Liquidity and Capital Resources

Capital Requirements

The following table presents PGE’s estimated cash requirements for the years indicated (in millions, excluding AFDC):

	2014	2015	2016	2017	2018
Ongoing capital expenditures (1)	$ 320	$ 300	$ 305	$ 280	$ 275
Port Westward Unit 2	130	15	—	—	—
Tucannon River Wind Farm	395	10	—	—	—
Carty Generating Station	115	165	35	—	—
Hydro licensing and construction (2)	40	20	10	5	5
Total capital expenditures	$ 1,000 (3)	$ 510	$ 350	$ 285	$ 280
Long-term debt maturities	$ —	$ 375	$ 67	$ 58	$ 75

(1) Consists primarily of upgrades to, and replacement of, transmission, distribution, and generation infrastructure, as well as new customer connections.
(2) Relates primarily to modifications to the Company’s hydro facilities to enhance fish passage and survival, as required by conditions contained in the operating licenses.
(3) Includes preliminary engineering and removal costs, which are included in other net operating activities in the condensed consolidated statements of cash flows.

For additional information on PW2, Tucannon River, and Carty, see *“Capital Requirements and Financing”* in the Overview section of this Item 2.

For a discussion concerning PGE's ability to fund its future capital requirements, see *"Debt and Equity Financings"* in this Item 2.

Liquidity

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

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

	Six Months Ended June 30,	
	2014	**2013**
Cash and cash equivalents, beginning of period	$ 107	$ 12
Net cash provided by (used in):		
Operating activities	302	279
Investing activities	(494)	(259)
Financing activities	182	87
Change in cash and cash equivalents	(10)	107
Cash and cash equivalents, end of period	$ 97	$ 119

Cash Flows from Operating Activities—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, such as depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. The $23 million increase in net cash flows from operating activities in the first half of 2014 compared with the first half of 2013 was largely due to an increase in Net income, net of non-cash items, and an increase in cash received from the Bonneville Power Administration to be returned to customers pursuant to the Residential Exchange Program. These increases were partially offset by an increase in coal inventory at the Company's Boardman plant.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. PGE estimates that such charges in 2014 will range from $295 million to $305 million. Combined with other sources, total cash expected to be provided by operations is estimated to range from $540 million to $560 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 distribution, transmission, and generation facilities. The $235 million increase in net cash used in investing activities in the first half of 2014 compared with the first half of 2013 was driven by a $241 million increase in capital expenditures resulting from the construction of three new generation projects (PW2, Tucannon River and Carty).

The Company plans approximately $1 billion of capital expenditures for 2014, which compares to 2013 capital expenditures of $656 million. PGE plans to fund the 2014 capital expenditures with cash expected to be generated from operations during 2014, as discussed above, as well as with issuances of debt securities. For additional information, see *"Capital Requirements"* and *"Debt and Equity Financings"* in the Liquidity and Capital Resources section of this 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 first half of 2014, net cash provided by such activities consisted of net proceeds received from the issuances of term bank loans of $225 million, partially offset by the payment of dividends of $43 million. During the first half of 2013, net cash provided by financing activities consisted of net proceeds received from the issuance of common stock in the amount of $47 million and FMBs in the amount of $148 million, partially offset by the repayment of FMBs of $50 million and commercial paper of $17 million, and the payment of dividends of $41 million.

Dividends on Common Stock

While the Company expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. 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 2014 consist of the following:

Declaration Date	Record Date	Payment Date	Dividends Declared Per Common Share
February 19, 2014	March 25, 2014	April 15, 2014	$ 0.275
May 7, 2014	June 25, 2014	July 15, 2014	0.280
July 24, 2014	September 25, 2014	October 15, 2014	0.280

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, capital expenditure requirements, alternatives available to investors, and other factors. The Company's ability to obtain and renew such financing depends on its credit ratings, as well as on credit markets, both generally and for electric utilities in particular. Management believes that the availability of credit facilities, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient cash and liquidity to meet the Company's anticipated capital and operating requirements. However, the Company's ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions.

PGE expects to fund 2014 estimated capital requirements with cash from operations (which is expected to range from $540 million to $560 million) and a combination of proceeds from long-term bank loans and issuances of FMBs. The balance of the common stock available under the EFSA is expected to be issued in the first half of 2015, with none expected in 2014.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $900 million through February 6, 2016 and currently has the following unsecured revolving credit facilities:

- A $400 million syndicated credit facility scheduled to expire November 2018; and
- A $300 million syndicated credit facility scheduled to expire December 2017.

These revolving credit facilities supplement operating cash flow and provide a primary source of liquidity. Pursuant to the terms of the agreements, the revolving credit facilities may be used for general corporate purposes, backup for commercial paper borrowings, and the issuance of standby letters of credit.

As of June 30, 2014, PGE had no borrowings outstanding under the revolving credit facilities, no commercial paper outstanding, and $9 million of letters of credit issued. As of June 30, 2014, the aggregate available capacity under the revolving credit facilities was $691 million.

Additionally, the Company has two letters of credit facilities under which it may issue letters of credit in an aggregate amount not to exceed $60 million. As of June 30, 2014, the Company had $54 million of letters of credit issued, with an aggregate available capacity under the letters of credit facilities of $6 million.

Long-term Debt. During the first half of 2014, PGE entered into two long-term debt transactions, which are described below.

- In May, PGE entered into an unsecured credit agreement with certain financial institutions, under which, the Company may obtain four separate term loans in an aggregate principal amount of $305 million. During the second quarter of 2014, PGE obtained three $75 million term loans, for an aggregate amount of $225 million. The Company obtained the fourth term loan in the amount of $80 million on July 21, 2014. The interest rate for the loans is LIBOR plus 70 basis points.

  The credit agreement expires October 30, 2015, 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.

- In May, PGE entered into a bond purchase agreement with certain institutional buyers under which the Company agreed to issue, in three tranches, an aggregate principal amount of $280 million of FMBs as follows:
  1. On or about August 15, 2014, $100 million of 4.39% Series FMBs due 2045;
  2. On or about October 15, 2014, $100 million of 4.44% Series FMBs due 2046; and
  3. On or about November 17, 2014, $80 million of 3.51% Series FMBs due 2024.

As of June 30, 2014, total long-term debt outstanding was $2,141 million, of which $70 million matures in January 2015 and is classified as current. In addition, PGE owns $21 million of its Pollution Control Revenue Bonds, which may be remarketed at a later date, at the Company's option.

Equity. PGE has an EFSA, whereby a forward counterparty borrowed 11,100,000 shares of the Company's common stock from third parties and such borrowed shares were sold in a registered public offering in 2013. PGE receives proceeds from the sale of the common stock when the EFSA is physically settled. In 2013, the Company issued 700,000 shares pursuant to the EFSA and received net proceeds of $20 million. As of June 30, 2014, the Company could have physically settled the EFSA by delivering 10,400,000 shares of PGE common stock to the forward counterparty in exchange for cash of $281 million. The Company anticipates physical settlement of the EFSA by delivery of newly issued shares on or before June 11, 2015. For additional information on the EFSA, see Note 6, Equity, in the Notes to the Condensed Consolidated Financial Statements.

Capital Structure. PGE's financial objectives include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. The Company attempts to maintain a common equity ratio (common equity to total consolidated capitalization, including any current debt maturities) of approximately 50%. Achievement of this objective, while sustaining sufficient cash flow, is necessary to maintain investment grade credit ratings and allow access to long-term capital at the most favorable interest rates available. PGE's common equity ratios were 46.6% and 48.7% as of June 30, 2014 and December 31, 2013, respectively.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's Investors Service (Moody's) and Standard and Poor's Ratings Services (S&P). PGE's current credit ratings and outlook are as follows:

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

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

As of June 30, 2014, PGE had posted approximately $20 million of collateral with these counterparties, consisting of $2 million in cash and $18 million in letters of credit. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of June 30, 2014, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade was approximately $53 million and decreases to approximately $29 million by December 31, 2014, and $21 million by

December 31, 2015. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade was approximately $125 million at June 30, 2014 and decreases to approximately $90 million by December 31, 2014, and $62 million by December 31, 2015.

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 under the credit facilities would increase.

The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the FMBs. PGE estimates that on June 30, 2014, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $846 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 has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65.0% of total capitalization (debt ratio). As of June 30, 2014, the Company's debt ratio, as calculated under the credit agreements, was 53.4%.

Off-Balance Sheet Arrangements

PGE has an EFSA, which the Company may settle with the issuance of PGE common stock, for cash or net share settlement from time to time, in whole or part, through June 11, 2015. For additional information on the EFSA, see Note 6, Equity, in the Notes to the Condensed Consolidated Financial Statements.

In May 2014, the Company entered into a the bond purchase agreement, under which PGE agreed to sell certain institutional buyers, in three tranches, an aggregate principal amount of $280 million of FMBs. PGE expects to issue the FMBs between mid-August and mid-November 2014. For further information, see "*Long-term Deb*t" in Note 2, Balance Sheet Components, in the Notes to Condensed Consolidated Financial Statements.

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

Contractual Obligations

PGE's contractual obligations for 2014 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, 2013, filed with the SEC on February 14, 2014. Such obligations have not changed materially as of June 30, 2014, with the following exception:

- During the second quarter of 2014, PGE obtained three $75 million term loans pursuant to a credit agreement, for an aggregate amount of $225 million. The interest rate for the loans is based on LIBOR. The credit agreement expires October 30, 2015, at which time any amounts outstanding under the term loans become due and payable.

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, 2013, filed with the SEC on February 14, 2014.

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

PGE's management, under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures as required by Exchange Act Rule 13a-15(b) as of the end of the period covered by this report. Based on that evaluation, PGE's Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2014, 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, 2013, filed with the SEC on February 14, 2014.

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

In September 2013, the plaintiffs filed an amended complaint that withdrew Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects. The CSES co-owners have filed a motion to dismiss all of the claims in the amended complaint. In April 2014, the parties entered into an agreement under which, following the court's decision on the motion to dismiss, plaintiffs will move to amend the complaint to limit the scope of the claims to thirteen projects. On May 22, 2014, the federal magistrate judge issued a recommendation to deny most of the motion to dismiss. The parties are awaiting a final decision on the motion to dismiss. This matter is scheduled for trial in June 2015.

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, 2013, filed with the SEC on February 14, 2014.

Item 6. Exhibits.

Exhibit Number	Description
3.1	Third Amended and Restated Articles of Incorporation of Portland General Electric Company (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed May 9, 2014).
3.2	Tenth Amended and Restated Bylaws of Portland General Electric Company (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed May 9, 2014).
10.1	Credit Agreement dated May 7, 2014, between Portland General Electric Company, Wells Fargo Bank, National Association, as Administrative Agent, and JPMorgan Chase Bank, N.A., U.S. Bank National Association, and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 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:	July 28, 2014	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: July 28, 2014

By: /s/ James J. Piro

James J. Piro

President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, James F. Lobdell, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Portland General Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the period presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date:	July 28, 2014	By:	/s/ James F. Lobdell
			James F. Lobdell
			Senior Vice President of Finance, *Chief Financial Officer and Treasurer*

Exhibit 32

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

We, James J. Piro, President and Chief Executive Officer, and James F. Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the “Company”), hereby certify that the Company’s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014, as filed with the Securities and Exchange Commission on July 29, 2014 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the “Report”), fully complies with the requirements of that section.

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

/s/ James J. Piro	/s/ James F. Lobdell
James J. Piro	James F. Lobdell
President and Chief Executive Officer	*Senior Vice President of Finance, Chief Financial Officer and Treasurer*
Date: July 28, 2014	Date: July 28, 2014